DIRECT TESTIMONY AND EXHIBITS

OF

BRIAN HORII

ON BEHALF OF THE

SOUTH CAROLINA OFFICE OF REGULATORY STAFF

DOCKET NO. 2019-182-E

IN RE: SOUTH CAROLINA ENERGY FREEDOM ACT (H.3659) PROCEEDING INITIATED PURSUANT TO S.C. CODE ANN. SECTION 58-40-20(C): GENERIC DOCKET TO (1) INVESTIGATE AND DETERMINE THE COSTS AND BENEFITS OF THE CURRENT NET ENERGY METERING PROGRAM AND (2) ESTABLISH A METHODOLOGY FOR CALCULATING THE VALUE OF THE ENERGY PRODUCED BY CUSTOMER-GENERATORS

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND OCCUPATION.

My name is Brian Horii. My business address is 44 Montgomery Street, San Francisco, California 94104. I am a Senior Partner with Energy and Environmental Economics, Inc. ("E3"). Founded in 1989, E3 is an energy consulting firm with expertise in helping utilities, regulators, policy makers, developers, and investors make the best strategic decisions possible as they implement new public policies, respond to technological advances, and address customers' shifting expectations.

Q. PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A. I have over thirty (30) years of experience in the energy industry. My areas of expertise include avoided costs, utility ratemaking, cost-effectiveness evaluations, transmission and distribution planning, and distributed energy resources. Prior to joining E3 as a partner in 1993, I was a researcher in Pacific Gas and Electric Company's ("PG&E") Research & Development department and was a supervisor of electric rate design and revenue allocation. I have testified before commissions in California, British Columbia, and Vermont, and have prepared testimonies and avoided cost studies for utilities in New York, New Jersey, Texas, Missouri, Wisconsin, Indiana, Alaska, Canada and China.

I received both a Bachelor of Science and Master of Science degree in Civil Engineering and Resource Planning from Stanford University. My full curricula vita is provided as Exhibit BKH-1. My prior work experience in this subject matter includes the following:

- Developed the methodology for calculating avoided costs used by the California Public Utilities Commission for evaluation of Distributed Energy Resources ("DER") since 2004;
- Developed the methodology for calculating avoided costs used by the California Energy Commission for evaluation of building energy programs;
- Authored avoided cost studies for BC Hydro, Wisconsin Electric Power Company, and PSI Energy;
- Provided review of, and corrections to, PG&E avoided cost models used in their general electric rate case;
- Developed the integrated planning model used by Con Edison and Orange and Rockland Utilities to determine least cost DER supply plans for their network systems;

- Developed the hourly generation dispatch model used by El Paso Electric Company to evaluate the marginal cost impacts of their off-system sales and purchases;
- Produced publicly vetted tools used in California for the evaluation of energy efficiency programs, distributed generation, demand response, and storage programs;
- Analyzed the cost impacts of electricity generation market restructuring in Alaska, Canada, and China; and
- Developed the "Public Tool" used by California stakeholders to evaluate Net Energy Metering ("NEM") program revisions in California.

Q. HAVE YOU TESTIFIED PREVIOUSLY BEFORE THE PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA ("COMMISSION")?

A. Yes, I previously prepared testimony and/or testified before this Commission on behalf of ORS in the Annual Fuel Clause Adjustment cases (Docket Nos. 2017-2-E, 2018-2-E, 2019-2-E) and the Act 62 Avoided Cost cases (Docket Nos. 2019-184-E, 2019-185-E, and 2019-186-E).

Q. WHY WERE YOU RETAINED BY ORS IN THIS PROCEEDING?

A. ORS retained E3 to conduct analysis, review, and develop recommendations regarding the requirements of Section 58-40-20(C) of the South Carolina Energy Freedom Act ("Act 62") which are to:

> (1) Investigate and determine the costs and benefits of the current net energy metering ("NEM") program; and
>
> (2) Establish a methodology for calculating the value of the energy produced by customer-generators.

ORS also retained E3 to address the use of avoided and embedded cost of service in the design of the Solar Choice Metering Tariffs to be considered by the Commission in future proceedings pursuant to Section 58-40-20(F) of Act 62.

Q. ARE YOU SPONSORING ANY EXHIBITS ALONG WITH YOUR TESTIMONY?

A. Yes. In addition to my curricula vitae (Exhibit BKH-1), I am sponsoring a report written in 2018 by E3 which summarizes relevant key issues addressed by stakeholders during the discussions for a potential Version 2.0 of Act 236 (Exhibit BKH-2). In particular, this report includes an estimate of the value of customer generators cost shift, as well as a broader discussion of rate design principles. Both of these topics are relevant to the discussions in this generic docket.

METHODOLOGY TO VALUE NEM PROGRAMS

Q. S.C. CODE ANN. SECTION 58-40-20(C) DIRECTS THE COMMISSION TO, AMONG OTHER THINGS, INVESTIGATE AND DETERMINE THE COSTS AND BENEFITS OF THE CURRENT NET ENERGY METERING PROGRAM. WHAT TYPES OF COSTS AND BENEFITS DO YOU BELIEVE SHOULD BE INVESTIGATED?

A. The investigation of the current NEM program should certainly consider cost and benefit impacts to the utility. In most cases, NEM systems can result in lower utility costs (benefits), such as lower energy production and procurement costs, lower generation capacity acquisition costs, and lower transmission and distribution ("T&D") capacity costs. Related to the change in energy production costs, there may also be reductions in environmental compliance costs such as those associated with coal ash ponds. All of these cost impacts (benefits) should be included in the investigation.

Also, in some cases NEM systems can result in cost increases for a utility. Dominion Energy South Carolina, Inc. ("DESC"), Duke Energy Carolinas, LLC and Duke Energy Progress, LLC (collectively known as "Duke") all provided testimony in Docket Nos. 2019-184-E, 2019-185-E, and 2019-186-E related to the increased costs experienced by the utilities to integrate large amounts of solar into the reliable operation of the grid. Also, in jurisdictions with high amounts of behind-the-meter solar, there can also be cost increases attributed to the utility's need to accommodate reverse flows of uncontrolled solar power from the customer up through the utility distribution system. Such increases in costs for the utility should also be included in the valuation of the NEM program.

Q. OTHER JURISDICTIONS INCLUDE ADDITIONAL BENEFITS SUCH AS THE SOCIAL VALUE OF CARBON DIOXIDE ("CO_2") REDUCTIONS IN THEIR RESOURCE EVALUATIONS. PLEASE DESCRIBE THE APPROACH SOUTH CAROLINA SHOULD USE TO INVESTIGATE SUCH BENEFITS?

A. There are a myriad of additional social or market benefits that can be provided by distribution renewable resources like behind-the-meter solar. CO_2 value, healthcare and mortality impacts from criteria pollutant reductions, market price impacts, and increased jobs are a few. Of these, benefits that rely upon the existence of wholesale energy or capacity markets (such as market price multiplier or Demand Reduction Induced Price Effect) should not be included since South Carolina does not have active markets.

The other benefits can be investigated and quantified, and Section 58-40-20(C) of Act 62 explicitly recognizes "the indirect economic impact of the net energy metering program to the State." However, such indirect impacts should not be included in the primary valuation of NEM. Rather, such benefits can be included in consideration of the tradeoffs between the goal of eliminating "any cost shift to the greatest extent practicable" and the South Carolina General Assembly's intent to "avoid disruption to the growing market for customer-scale distributed energy resources."

Q. CAN YOU PROVIDE AN EXAMPLE OF HOW INDIRECT ECONOMIC BENEFITS SHOULD BE INCLUDED IN THE DEVELOPMENT OF THE SOLAR CHOICE METERING TARIFF?

A. Yes. Assume that the direct economic benefits (energy-related, generation capacity, T&D capacity, and environmental compliance) average $100 per month for a new NEM solar system installed behind a customer's meter. Further, assume that the bill savings for a customer installing solar averages $150 per month under the Solar Choice Metering Tariff under consideration. This indicates that there is a $50/month cost shift from the NEM customer to all utility customers (note that the NEM customer will also see an increase in the future to accommodate the cost shift, so all customers bear the cost shift, not just non-NEM customers).

Now if the indirect economic benefits were $80 per month, then one could more easily accept a $50 per month cost shift since that solar system is providing more benefits (including indirect) than the bill reduction that is "funding" the solar system.

Conversely, if the indirect economic benefits were only $20 per month, then one could argue that the solar tariff is too favorable to solar, and that there is a net economic loss to the State from incentivizing solar at that level. In that situation the Commission may see it as reasonable to place more importance on the minimization of the cost shift recognizing that there may be some slowing of the distributed energy resource ("DER") market.

Q. PLEASE PROVIDE RECOMMENDATIONS ON HOW THE COMMISSION SHOULD BALANCE THE CONFLICTING GOALS OF COST SHIFT MINIMIZATION AND SUPPORT OF THE DER MARKET.

A. The Commission has a difficult task under Act 62. Rate design is a process that is part analytical and part practical with a lot of professional judgement thrown into the mix. It will be difficult for the Commission to balance the goals of cost shift minimization and support of the DER market without a thorough review of each utility's Solar Choice Metering Tariff and underlying data. I am concerned that the non-solar customer may be at a disadvantage during this generic proceeding. The Commission should take care to assure that the balance is not overly shifted in favor of the DER market.

Q. S.C. CODE ANN. SECTION 58-40-20(D) DIRECTS THE COMMISSION TO CONSIDER FIVE (5) SPECIFIC COMPONENTS IN ITS EVALUATION OF THE COSTS AND BENEFITS OF NEM. IS THERE THE POTENTIAL FOR CONFUSION IN REGARD TO THESE COMPONENTS?

A. Yes. The language of the section is as follows:

> (D) In evaluating the costs and benefits of the net energy metering program. the commission shall consider:

> (1) the aggregate impact of customer-generators on the electrical utility's long-run marginal costs of generation. distribution, and transmission;
>
> (2) the cost of service implications of customer-generators on other customers within the same class, including an evaluation of whether customer-generators provide an adequate rate of return to the electrical utility compared to the otherwise applicable rate class when, for analytical purposes only, examined as a separate class within a cost of service study;
>
> (3) the value of distributed energy resource generation according to the methodology approved by the commission in Commission Order No. 2015-194;
>
> (4) the direct and indirect economic impact of the net energy metering program to the State; and
>
> (5) any other information the commission deems relevant.

Within the section are references to four (4) different types of costs or benefits: 1) long-run marginal costs, 2) cost of service studies, 3) direct and indirect economic costs, and 4) the methodology from Commission Order No. 2015-194. It is important that this generic proceeding carefully define what these terms mean and indicate the major differences between them. This will establish a framework that the Commission can apply to evaluate each Solar Choice Metering Tariff proposal.

Q. PLEASE EXPLAIN YOUR RECOMMENDATION FOR DEFINING: 1) LONG-RUN MARGINAL COSTS, 2) COST OF SERVICE STUDIES, 3) DIRECT AND INDIRECT ECONOMIC COSTS, AND 4) THE METHODOLOGY FROM COMMISSION ORDER NO. 2015-194.

A. To help clarify these terms, I provide the following simple definitions:

(1) **Long-run Marginal Costs.** Marginal costs are the change in the costs of providing electrical service due to a small change in demand. For example, in energy production, the marginal cost is typically the cost of changing output of the most expensive to operate plant that is producing power. It is important to note that marginal costs are different from average costs, which reflect the costs of the output of all plants.

For example, consider a simple utility with two (2) natural gas generators: Generator "A" produces electricity at a cost of $50 per megawatt-hour ("MWh") and can produce up to 80 megawatts ("MW"). Generator "B" produces electricity at a cost of $100/MWh and can produce up to 50 MW. If load during a particular hour were 100 MW, then both generators would have to be turned on and generating. The marginal cost for electricity during that hour would be the cost of the most expensive generator, generator B, at $100/MWh, while the average cost would be $60/MWh (($50/MWh * 80 MW + $100/MWh * 20 MW)/ 100 MW).

The qualifier "long-run" indicates that the marginal cost should not just reflect changes in variable costs, but also consider changes in "fixed" factors such as generation, transmission, and distribution assets. In the above example, if load were forecast to be high enough to require construction of a new generator, then the long-run marginal cost would include the cost of adding that new generator's capacity. Similarly, if load changes required the construction of T&D facilities to meet demand, the long-run marginal costs could include new T&D as well.

(2) **Cost of Service ("COS") studies**. COS studies are used to assign the total revenue requirement of a utility to each class of customers. COS studies are also referred

to as Embedded Cost studies since they are focused on recovering the cost of historical (embedded) investments and current operating expenses.[1] Unlike marginal costs studies that look at *changes* in costs, COS studies look at how to divide a utility's total accounting costs among customer classes such as residential, commercial, and industrial.

(3) **Direct and Indirect Economic Costs.** Given that these are general terms, it is useful to define them in the context of this generic docket. Indirect Economic Costs is an extremely broad term that could apply to a myriad of situations such as impacts on upstream suppliers, impacts on other sectors of the South Carolina economy, non-utility-bill impacts on utility costs, etc. The Commission should clearly define the terms to assist with development of a framework for evaluation. I recommend the terms be defined as follows:

3a) **Direct Economic Costs.** Costs or benefits (reductions in costs) that would impact utility customer bills or utility shareholder earnings. Examples include energy generation or procurement costs; generation, transmission, or distribution capacity expansion projects; environmental compliance costs associated with power production or delivery.

3b) **Indirect Economic Costs**. Costs or benefits that may accrue to the South Carolina economy in general and South Carolina utility customers in particular due to DER. Examples include healthcare and mortality benefits of reduced grid energy production, reduced environmental damage or future abatement costs from reductions of

[1] Some jurisdictions like California use marginal costs to determine how to allocate the total utility costs, but this is not the common practice, so will not be discussed herein.

CO_2 emissions, and the net benefits of the increase in South Carolina economic activity due to DER.

(4) **Methodology from Commission Order No. 2015-194.** This Commission Order established an NEM Methodology for determining the value of NEM DER. The methodology presents eleven (11) categories of avoided costs. The avoided costs are all "direct" economic impacts that the methodology describes as both "avoided" costs and "marginal" costs in the descriptions. The terms "marginal cost" and "avoided cost" can be considered synonymous. Marginal cost is the term generally used in economic theory and in the discussion of the derivation of cost changes. It is more general in that it does not imply the cost change is always an avoidance of costs. Avoided cost is the term generally used in the valuation of resources because the context is a comparison of the cost of the resource versus the costs that can be avoided by its acquisition. An avoided cost, however, can be negative (an increase in cost) in some situations, so the Commission can use the terms marginal cost and avoided cost interchangeably.

Q. HOW COULD MARGINAL COSTS BE USED TO DETERMINE THE COST SHIFT ASSOCIATED WITH NEM SOLAR?

A. Solar systems or any demand side management ("DSM") options reduce customer bills through reductions in the amount of electricity the customer needs to purchase from a utility. At the same time, this reduced usage results in lower costs for the utility to provide service because of lower power procurement or production related costs as well as lower generation plant and delivery equipment costs. These utility cost savings are the marginal cost savings from the NEM solar and DSM options. The bill savings minus the marginal cost savings are one definition of the cost shift.

Q. PLEASE EXPLAIN HOW AN EMBEDDED COST OF SERVICE STUDY CAN BE USED TO DETERMINE THE COST SHIFT.

A. An embedded COS study that allocates costs to customers with NEM solar and demand response ("DR") as if they were their own separate class of customers separate from "regular" non-solar customers can be used to determine cost shift due to NEM. The cost shift would be the difference between the costs allocated to these NEM solar and DR customers in the study compared to what those customers would pay under the otherwise applicable rate. The concept is that the embedded cost allocation represents what those customers "should" pay based on their usage characteristics if they were treated the same as all other customers and customer classes.

Q. ARE THERE STUDY APPROACHES THAT SHOULD BE CONSIDERED WHEN LOOKING AT A COST SHIFT ESTIMATED USING AN EMBEDDED COS STUDY?

A. Yes. Cost shift calculations using an embedded COS study are often premised on three (3) calculation steps and there are important framework decisions for each step.

The first step is to determine the otherwise applicable rate that will be used as the basis for comparison. One could use a) actual current rates, b) the rates determined by an embedded COS study using the same data, but not separating out the NEM customers, or c) an entirely new set of rates. Studies that look backward at the historical cost shift would generally use option "a," actual rates, as the comparison rate. For evaluating the future cost shift associated with a new Solar Choice tariff, option "c" would be the preferred option, with the proposed Solar Choice Metering Tariff as the comparison rate.

The second step is to determine the year to use for the embedded COS study. This is the "test year" in COS study parlance. A COS study can use a historical or a future test year for the accounting costs to be allocated. Duke indicated that they used a future year (2024) for their embedded COS studies, and I believe this use of a future year is appropriate for making decisions about the future Solar Choice Metering Tariff.

The third step is whether energy usage and demand metrics should reflect historical or future conditions. This choice is more important than the choice of the test year for accounting purposes. Given how the timing of the need for generation capacity has changed in South Carolina, and the potential for distribution capacity peaks to also shift to later in the day or evening due to distributed solar, the demand metrics should reflect these new realities and be based on future conditions if possible.

Q. E3 PREPARED A COST SHIFT ANALYSIS FOR ORS BASED ON MARGINAL COSTS BACK IN 2018. DUKE DISCUSSED COST SHIFT ESTIMATES BASED ON A COS STUDY IN THEIR SOLAR CHOICE METERING TARIFF SETTLEMENT MATERIALS. HOW DO THE TWO ESTIMATES COMPARE?

A. Duke estimates a cost shift of $35-40 per month per NEM solar customer. E3 estimated a cost shift of about $45 per month per NEM solar customer. Some of the difference is likely due to outdated or overly simplistic assumptions used in the embedded COS study. I suspect, however, that much of the difference is due to the E3 study cost shift results being based on marginal cost savings, whereas the Duke cost shift is from the embedded COS approach.

Q. PLEASE EXPLAIN WHY THE MARGINAL COST AND EMBEDDED COST APPROACHES COULD ARRIVE AT DIFFERENT ESTIMATES OF THE COST SHIFT.

A. Marginal costs are generally used when performing cost effectiveness studies and making resource decisions. Embedded costs are generally used to determine the share of utility costs for which different customer classes should be responsible. The marginal cost and embedded cost approaches are really answering two (2) different questions. Avoided costs answer the economic question of "what is the <u>cost impact</u> of the customer changing their usage pattern with DER." The COS study answers the question of "<u>How much should I charge</u> the customer after they have installed the DER."

Let's use a limousine company to illustrate. Say the average total cost of a trip is $10 --- that is what you need for your business to cover all of your variable and fixed costs. That includes fuel, operating and maintenance ("O&M"), driver costs, vehicle costs, taxes, financing costs etc. Further assume that fuel and O&M costs are only $3 of that cost. So, of that $10 per trip fee, $7 ($10 trip fee – $3 variable costs) is going toward paying off your fixed costs, etc., and that $7 is your net loss for each time someone rides their bike instead of taking your limousine. If an existing customer switches to riding their bike instead of taking your limousine, to remain whole financially you would need to adjust your rates upward to capture that lost net revenue. In other words, $7 per lost trip is the cost shift amount for your business from a marginal cost perspective.

Now assume that if you looked closer at your business you would see that each trip really cost you only $7 for frequent users, and $12 for infrequent customers (the cost per trip for infrequent users is higher per trip because you still have vehicles, etc., that you need to keep available for when the customers decide to call you for service, but you are getting lower utilization of the vehicles). With this information you see that you are only getting $10 per trip from your infrequent customers (you charge all customers the same rate), while you really should be collecting $12 per trip. So, you could define your cost shift for infrequent customers as that $2 per trip difference ($12 that they should pay minus $10 that they are actually paying). Under the embedded COS study approach the cost shift is only $2 per trip for the infrequent customers.

From the marginal cost approach, the cost shift is $7 per lost ride. That is what now needs to be collected from all remaining rides for the limousine service to maintain the same profitability as before the reduction in rides. From the embedded COS approach, the cost shift is $2 per trip because that is how much actual rates are subsidizing the more expensive to serve (on a per rider basis) low frequency riders.

Q. GIVEN THAT THE TWO (2) APPROACHES PROVIDE DIFFERENT ESTIMATES OF THE COST SHIFT, WHICH METHOD SHOULD THE COMMMISSION RELY UPON FOR THE DESIGN OF THE SOLAR CHOICE METERING TARIFF?

A. Both estimates are valid and important for the Solar Choice Metering Tariff design discussion. The marginal-cost-based cost shift indicates the impact of a customer installing NEM solar at their premise. This is the immediate impact without any rate changes and assumes the bill prior to installation of NEM solar is the appropriate starting point. This issue of the appropriate starting point was one that E3 encountered in California in looking at early NEM cost shift results. The cost shift studies showed that bill reductions far exceeded the avoided cost savings of the solar installations, but the large bill savings were partly due to those customers "overpaying" for electricity due to a tiered rate system that was forced by the unintended result of legislation into severely high rates for high levels of usage.

The embedded COS study takes a different approach and does not assume that the bill prior to NEM solar is the correct starting point. Instead, the COS study determines its own starting point for the NEM solar customers by modeling the NEM solar customers as if they were a separate class or subclass. The embedded COS study then estimates the cost shift as the difference between its determination of the hypothetical "correct" rate for NEM solar customers versus the existing or proposed Solar Choice Metering Tariff.

Given these differences in approaches, the marginal cost approach is the more appropriate method to determine the cost shift that will occur due to customers installing behind-the-meter solar. The embedded COS approach, however, is important for evaluating the policy issue of whether the solar customers would be paying their fair share of costs, or as specified in S.C. Code Ann Section 58-40-20(D)(2): "whether customer-generators provide an adequate rate of return to the electrical utility compared to the otherwise applicable rate class when, for analytical purposes only, examined as a separate class within a cost of service study."

Q. SHOULD THE COST SHIFT E3 ESTIMATED IN THE 2018 REPORT (EXHIBIT BKH-2) BE RELIED UPON BY THE COMMISSION IN THIS DOCKET?

A. No. The 2018 Report provided useful data points regarding the magnitude of the potential cost shift at that time. However, the 2018 Report reflects dated assumptions related to the state of marginal costs in 2018 or a prior timeframe. In particular, the 2018 Report reflects the timing of the need for capacity based on the Public Utility Regulatory Policies Act of 1978 ("PURPA") purchase power tariffs in effect at the time. As these new Solar Choice Metering Tariffs will be for future NEM solar installations, the timing and the need for generation capacity should reflect these future needs. Also, the study, like the PURPA tariffs, included T&D capacity values of zero ($0). I believe that assumptions of zero ($0) T&D capacity value for NEM solar should be revised and a system average non-zero value be included in the marginal cost analysis used to inform any new NEM rates.

Q. PLEASE EXPLAIN ANY GENERAL CONCERNS REGARDING COST SHIFTS ESTIMATED BASED ON EMBEDDED COS ANALYSES.

A. Embedded COS studies typically use very rudimentary methods for determining causation compared to marginal cost methods. For example, good detailed marginal cost analyses look at the probabilistic need for capacity over the entire year. In contrast, embedded cost of service studies use simple metrics like loads during one single hour of the year, or peak loads of the customer class independent of the timing of capacity need on the electrical grid. Embedded COS studies are therefore generally far less precise than marginal cost analyses.

Q. PLEASE EXPLAIN WHY MORE SCRUTINY SHOULD BE APPLIED BY THE COMMISSION TO ANY EMBEDDED COST OF SERVICE STUDY OF CUSTOMERS WITH NEM SOLAR GENERATION THAN THAT GIVEN TO TRADITIONAL EMBEDDED COST OF SERVICE STUDIES.

A. Due to the increased complexity of modern grids with renewable generation, and the increased sophistication of many aspects of utility operations and planning, traditional embedded cost methods may be out of step with current and future cost causation. When considering costs to be allocated to a customer class, the Commission should include all customer-incurred costs related to use of the utility grid. These include the standard cost items that are traditionally included in embedded COS studies such as production, transmission, distribution, and customer-related costs. With increasing levels of behind-the-meter solar, however, a COS study needs to allocate costs based on a customer's maximum use of the grid, whether in the normal (grid power flowing to the customer) or reverse (customer power flowing to the grid) direction.

The study should also include any costs for new grid investments to address reverse flow as well NEM solar grid integration costs which would likely be exacerbated by drops in distributed solar generation.

Q. PLEASE EXPLAIN THE SPECIFIC CONCERNS RELATED TO THE DUKE EMBEDDED COST OF SERVICE STUDY.

A. During a call with ORS, Duke conveyed that the COS study allocated generation capacity costs using Summer 1 coincident peak ("CP") as the demand metric. Summer 1 CP means that generation capacity costs are allocated based on each class's demand at the time of the maximum system peak hour in the summer. This might have been an appropriate way to represent how each class caused the need for generation capacity a few years ago. However, Duke is no longer a solely summer peaking system, and winter has become the predominant season for generation need. In Docket No. 2019-185-E, Duke witness Glen Snider testified that as of the Companies' 2018 integrated resource plan ("IRP"), "100% of DEP's loss of load risk occurs in the winter and approximately 90% of DEC's loss of load risk occurs in the winter."[2] While ORS found issues with those specific loss of load calculations, the fundamental driver still remains, that according to Duke's IRP criteria, Duke is facing more winter peaking supply constraints. Thus, it would be more appropriate to use a demand metric that is based on the Loss of Load Probability analysis that Duke already performed and used for its marginal cost-based rates.

By using the simple Summer 1CP demand metric, Duke is underestimating the capacity costs that should be allocated to the NEM solar customers. By using Summer 1CP, solar output in the summer substantially reduces the "peak" demand of the solar customers, therefore substantially reduces the demand-related costs allocated to the solar customers. If Duke used a more appropriate winter peak demand, then the solar output would have little impact on the demand metric since the solar output during the winter peaks are only a fraction of their output during the old summer peaks. This would then result in only a small reduction in demand-related costs allocated to solar customers which would increase the COS study's average allocated rates for the solar customers and increase the cost shift attributed to the solar customers.

[2] Direct Testimony of Glen A. Snider, Docket 2019-185-E, p. 19.

Q. IS COST SHIFT A UNIQUE PROBLEM FOR CUSTOMER-SITED NEM SOLAR?

A. No. Cost shift technically exists for any resource or customer decision that results in the customer having a usage pattern that differs from the usage pattern used to design the customer's rate (i.e.: the class average usage pattern). The cost shift problem is one borne out of the use of simplified rates that cannot reflect the true cost to serve customers. The simpler the rate, the worse the problem of cost shift as customers depart from the class average usage pattern. For residential solar, cost shift is a particularly important issue because residential rates are the simplest rates, and the solar changes to customer usage patterns are dramatic.

ASPECTS OF IDEAL MARGINAL COSTS

Q. PLEASE EXPLAIN THE IDEAL CHARACTERISTICS OF A METHOD FOR ESTIMATING MARGINAL COSTS.

A. Marginal costs represent the change in the cost to provide a good (energy, generation capacity, T&D capacity, etc.) due to small changes in demand from the good. To be useful for use in development of a Solar Choice Metering Tariff, the marginal costs should have the following characteristics:

1. **Based on future costs rather than past investments or costs.** Historical costs can be useful if they are indicative of future costs, but direct estimates of future costs are preferred.
2. **Reflect future conditions.** Absent the impact of the resources one wants to evaluate. Marginal costs are estimated as changes in costs relative to a base case. If you include future NEM solar in your base forecast, then the benefits provided by that solar could

already be reflected in your base case and may reduce the estimated marginal cost associated with further load reductions from solar. The issue arises because the avoided costs of a single resource like NEM solar generally decline as you add more of that resource to the system. For solar, this is particularly acute as the restricted output pattern of solar can shift the timing of the need for capacity. Each additional MW of solar is worth less and less to the system.

3. **Should not be unduly discriminatory against specific technologies.** However, if specific technologies result in cost changes that are not captured or reflected by other marginal cost components, it is appropriate to include an adjustment to the marginal costs. Cost-based differentiation by technology is reasonable.

Q. PLEASE PROVIDE EXAMPLES OF OTHER STATE JURISDICTIONS THAT USE THE MARGINAL COST METHODOLOGY TO EVALUATE THE COST AND BENEFIT OF NEM SOLAR.

A. The New York Department of Public Service released a white paper on rate design for NEM which calls for use of the marginal cost methodology,[3] and the California Public Utilities Commission ("CPUC") commissioned a study, to which E3 was a contributor, that used marginal cost methods in looking at costs and benefits of California's NEM program (NEM 2.0).[4]

[3] "Staff Whitepaper on Rate Design for Mass Market Net Metering Success Tariff" New York Department of Public Service, Case 15-E-0751 Matter 17-01277, December 2019.
[4] "Net Energy Metering 2.0 Lookback Study: Draft Report" available at https://verdantassoc.sharepoint.com/:b:/s/VerdantFileShare/EdNLX0qla9FBqNklaviDbE8BNkGDIyIWSB3OJBV8IFm9PA?e=uVqgj8

AVOIDED COST COMPONENTS

Q. WHAT SPECIFIC COMPONENTS SHOULD BE INCLUDED IN THE CALCULATION OF AVOIDED COSTS FOR THE PURPOSE OF ASSIGNING A VALUE TO NEM SOLAR?

A. The Commission approved an NEM methodology in Commission Order No. 2015-194, which included the set of avoided cost categories described in Table 1. The specific components and the high-level presentation of a uniform methodology to calculate the values are valid and should be continued. The review by the Commission and other parties of how the quantification methods for each specific category and the derived estimated values by the utilities remains critical.

Table 1: Value of NEM Distributed Energy Resource Methodology (from Commission Order No. 2015-194)

METHODOLOGY COMPONENT	CALCULATION METHODOLOGY/VALUE
+/- AVOIDED ENERGY	Component is the marginal value of energy derived from production simulation runs per the Utility's most recent Integrated Resource Planning ("IRP") study and/or Public Utility Regulatory Policy Act ("PURPA") Avoided Cost formulation.
+/- ENERGY LOSSES / LINE LOSSES	Component is the generation, transmission, and distribution loss factors from either the Utility's most recent cost of service study or its approved Tariffs. Average loss factors are more readily available, but marginal loss data is more appropriate and should be used when available
+/- AVOIDED CAPACITY	Component is the forecast of marginal capacity costs derived from the Utility's most recent IRP and/or PURPA Avoided Cost formulation. These capacity costs should be adjusted for the appropriate energy losses.
+/- ANCILLARY SERVICES	Component includes the increase/decrease in the cost of each Utility's providing or procurement of services, whether services are based on variable load requirements and/or based on a fixed/static requirement, i.e. determined by an N-1 contingency. It also includes the cost of future NEM technologies like "smart inverters" if such technologies can

	provide services like VAR support, etc.
+/- TRANSMISSION AND DISTRIBUTION ("T&D") CAPACITY	Marginal T&D distribution costs will need to be determined to expand, replace, and/or upgrade capacity on each Utility's system. Due to the nature of NEM generation, this analysis will be highly locational as some distribution feeders may or may not be aligned with the NEM generation profile although they may be more aligned with the transmission system profile/peak. These capacity costs should be adjusted for the appropriate energy losses.
+/- AVOIDED CRITERIA POLLUTANTS	The costs of these criteria pollutants are most likely already accounted for in the Avoided Energy Component, but, if not, they should be accounted for separately. The Avoided Energy component must specify if these are included.
+/- AVOIDED CO_2 EMISSION COST	The cost of CO_2 emissions may be included in the Avoided Energy Component, but, if not, they should be accounted for separately. A zero monetary value will be used until state or federal laws or regulations result in an avoidable cost on utility systems for these emissions.
+/- FUEL HEDGE	Component includes the increases/decreases in administrative costs of any Utility's current fuel hedging program as a result of NEM adoption and the cost or benefit associated with servicing a portion of its load with a resource that has less volatility due to fuel costs than certain fossil fuels. This value does not include commodity gains or losses and may currently be zero.
+/- UTILITY INTEGRATION & INTERCONNECTION COSTS	Costs can be determined most easily by detailed studies and/or literature reviews that have examined the costs of integration and interconnection associated with the adoption of NEM. Appropriate levels of photovoltaic penetration increases in South Carolina should be included.
+/- UTILITY ADMINISTRATION COSTS	Component includes the incremental costs associated with net metering, such as hand billing of net metering customers and other administrative costs.
+/- ENVIRONMENTAL COSTS	The environmental compliance and/or Utility system costs might be accounted for in the Avoided Energy component, but, if not, should be accounted for separately. The Avoided Energy component must specify if these are included. These environmental compliance and/or Utility system costs must be quantifiable and not based on estimates.

DISTRIBUTION AND TRANSMISSION AVOIDED CAPACITY COSTS

Q. SOME UTILITIES HAVE ARGUED IN OTHER JURISDICTIONS THAT IT IS NOT POSSIBLE TO CALCULATE A MEANINGFUL DISTRIBUTION AVOIDED COST BECAUSE DISTRIBUTION INVESTMENTS ARE SPECIFIC TO INDIVIDUAL LOCATIONS WITH PEAK TIMINGS THAT CAN DIFFER GREATLY. DO YOU AGREE THESE ARE VALID REASONS TO EXCLUDE DISTRIBUTION CAPACITY COSTS FROM THE MARGINAL COST ANALYSES FOR A SOLAR CHOICE METERING TARIFF?

A. No. While it is true that load growth related distribution investments are highly time and location specific, it is clearly possible to calculate distribution marginal capacity costs, and there are myriad examples of jurisdictions that do so. For example, a benchmarking study submitted to the Colorado PUC in 2014 includes a survey of avoided T&D costs for twenty (20) states or regions.[5]

Q. CAN A "MEANINGFUL" GLOBAL AGGREGATED DISTRIBUTION CAPACITY VALUE BE DEVELOPED?

A. Yes. It would be ideal to estimate individual distribution marginal capacity costs for each small subsegment of the utility distribution system that has a capacity need in the near term. However, absent that ideal situation, excluding distribution marginal capacity costs assumes that there is no distribution capacity value anywhere in the utility system,

[5] *Benchmarking Transmission and Distribution Costs Avoided by Energy Efficiency Investments*, Mendota Group, 2014, https://mendotagroup.com/wp-content/uploads/2018/01/PSCo-Benchmarking-Avoided-TD-Costs.pdf

and never would be any value. Clearly, this is wrong. It would be more appropriate to use a system average distribution capacity value than to exclude distribution capacity completely.

By including a distribution marginal cost, one recognizes the value to load reductions for the distribution system. In addition, for long-lived resources like solar, the use of system average distribution costs is especially valid and meaningful as distribution costs tend to revert to the mean over time. For example, Area A may have a high distribution marginal cost in year one (1), but after capacity investments are made in the area, the marginal cost drops to near zero (0) for many years. Conversely, Area B may have no distribution capacity cost in year one (1), but ten (10) years from now may have a high distribution marginal cost due to load growth eventually "using up" the surplus distribution capacity in the area that made it a zero (0) cost area in year one (1). By using a system average distribution marginal capacity cost, it smoothes out the ups and downs for individual areas and recognizes that there is a fundamental distribution value for load reductions.

Q. IS IT POSSIBLE FOR THE SOUTH CAROLINA UTILITIES TO DERIVE MORE PRECISE TIME AND LOCATION-SPECIFIC ESTIMATES (AS OPPOSED TO SYSTEM AVERAGE ESTIMATES) OF DISTRIBUTION MARGINAL CAPACITY COSTS?

A. Yes. This is in fact done in California. My objective here is not to describe the approach in detail, but to show that such a calculation is feasible. The CPUC has implemented a Distribution Resource Plan proceeding that requires the utilities to annually submit a Grid Needs Assessment ("GNA") and Distribution Deferral Opportunity Report ("DDOR"). These reports identify all distribution investments on the utility system over the next five (5) years, the grid need that is driving the investment (e.g. load growth, voltage, reliability), the $/kW-year cost of the investment, and whether it is feasible to defer the investment with DSM. Load forecasts for each distribution feeder are also provided, with the amount of DSM included in the forecast specifically identified. With this data of planned load growth related distribution investments and load forecasts with and without DSM, a calculation can be made for each feeder using the bottoms-up $/kW-year cost distribution investment required and avoided by DSM individually. The method is more fully described in the 2020 ACC Documentation.[6]

The data for the kind of detailed analysis discussed above is not commonly available for an entire utility service territory in most jurisdictions. The California example does show the highly time and location specific nature of distribution investment does not itself preclude calculating distribution avoided costs. That said, distribution avoided costs are more commonly calculated using far less data, and both DESC and Duke have provided estimates of T&D marginal capacity costs in response to Vote Solar et al's First Data request Items 7 (for DESC) and 11 (for Duke).

Q. IS THERE A SINGLE BEST APPROACH FOR CALCULATING TRANSMISSION AND DISTRIBUTION MARGINAL COSTS?

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[6] 2020 ACC Documentation v1c Final p. 48, ftp://ftp.cpuc.ca.gov/gopher-data/energy_division/EnergyEfficiency/CostEffectiveness/2020%20ACC%20Documentation%20v1c.pdf

A. No. There are several different methods commonly used by different utilities and jurisdictions. The study, "Benchmarking Transmission and Distribution Costs Avoided by Energy Efficiency Investments" by the Mendota Group, concluded that there are a number of methodologies to calculate T&D avoided costs and that there is no single approach to estimating these costs.[7] The study also provides example distribution avoided costs from at least twenty (20) different utilities, countering the assertion that meaningful, aggregated distribution avoided costs cannot be calculated for DSM programs.

Q. YOUR DISCUSSION CENTERS AROUND DISTRIBUTION CAPACITY. DO YOUR POINTS APPLY TO TRANSMISSION CAPACITY AS WELL?

A. Yes, and I recommend that transmission marginal capacity costs also be included. There are simple straightforward methods to calculate marginal T&D capacity costs with limited requirements for data. However, even for those simple methods, care must be exercised in developing the estimates. A review of DESC's data response to Vote Solar et al reveals that several adjustments are necessary to correct the T&D capacity estimate. Based on the information provided to Vote Solar et al by Duke, it appears that corrections to those T&D capacity costs would also be required.

Q. WHAT METHODOLOGY DID DESC USE TO CALCULATE THE MARGINAL COSTS PROVIDED IN THE DATA RESPONSE TO VOTE SOLAR ET AL'S FIRST DATA REQUEST ITEM NUMBER 7?

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[7] "Benchmarking Transmission and Distribution Costs Avoided by Energy Efficiency Investments for Public Service Company of Colorado," https://mendotagroup.com/wp-content/uploads/2018/01/PSCo-Benchmarking-Avoided-TD-Costs.pdf

A. DESC calculates the marginal cost of transmission, power delivery distribution, and retail operations distribution using a Total Investment Method ("TIM"). The power delivery and retail operations marginal costs are added together to equal the total distribution marginal cost. Each marginal cost is calculated in two (2) steps. First, DESC calculates the unit cost of the assets ($/kW). This is the average asset cost for each kW of system peak demand growth and represents an average cost of capacity needed to meet peak demand growth. The second step is to annualize the unit costs ($/kW) to convert the unit costs into the form used for marginal costs ($/kW-year). This annualization step incorporates various adders and multipliers so that the marginal cost represents the full cost impact on utility customers. The adders and multipliers account for income taxes, property taxes, insurance, the gross receipts and Commission tax, as well as return of and on capital.

While there are other more detailed methods for estimating marginal T&D capacity costs, the DESC approach is a method that has been adopted by Commissions to estimate marginal costs.

Q. DO YOU HAVE CONCERNS REGARDING THE LOAD GROWTH FORECAST DESC USES IN ITS CALCULATIONS?

A. Yes. DESC is deriving the distribution marginal costs based on the implicit assumption that system growth causes the need for the distribution capacity additions. However, it is the individual peak demand on individual distribution equipment, or aggregate peak demand on a small group of distribution equipment that causes the need for capacity additions. This distribution peak demand (total peak demand of the individual distribution equipment or groups of distribution equipment) will be larger than the system peak because not all distribution assets have their peak demands at the same time as the system. By using system demand, DESC is using an overly small estimate of demand growth for its unit cost derivation and this results in an overestimate of the marginal cost of distribution capacity.

Q. HOW CAN DESC CORRECT THIS OVERESTIMATION PROBLEM?

A. DESC currently calculates the unit cost of distribution capacity ($/kW) by dividing the sum of five (5) years of investments by the five-year growth in system demand. The ideal correction would be to replace the five-year growth in system demand with the five-year growth in distribution peak demand.

If this correction were made, I estimate DESC's marginal distribution capacity costs would be reduced by 23%. I calculated this reduction using the hourly distribution substation data provided by DESC in response to Vote Solar et al's first data request item 8e. The hourly data allows calculation of the simultaneous peak of the aggregated load of all of the provided distribution substations.[8] The simultaneous, or coincident, peak is analogous to the system peak that DESC is currently using for the marginal cost estimate. The hourly data also allows calculation of the peak demand for each substation, regardless of when that occurs in the year. The sum of the individual noncoincident substation peaks is indicative of the peak demands that drive the need for distribution capacity additions. Some investments may be driven by circuit peaks, transformer peaks, or aggregate peaks of a group of distribution substations. However, the noncoincident distribution peaks are a

[8] The data set does not include information for all distribution substations, but since we are using this data to derive an adjustment factor, rather than an absolute adjustment, the missing data is not crucial to the results.

closer proxy for those demands than the system peak. The 23% reduction is calculated using the following formula:

Marginal Distribution Cost Reduction % = 1 – (Coincident peak of substations / Sum of substation noncoincident peaks)

Q. DESC ESTIMATES MARGINAL DISTRIBUTION CAPACITY COSTS USING INVESTMENT EXPENDITURES FROM 2017 THROUGH 2021. HOWEVER, THE GROWTH IS ESTIMATED FOR THE YEARS 2019 THROUGH 2024. PLEASE EXPLAIN THE CONCERNS ABOUT A MISMATCH IN THE FORECAST TIME PERIOD.

A. The growth should match the years of the investments, or perhaps be ahead of the expenditures to reflect project commitment dates that precede the expenditures. Growth that occurs after the expenditures is not relevant for marginal cost calculations, because that growth would not have caused the need for the projects. That said, the DESC growth forecast appears to be stable from year to year, so I propose no change at this time, but encourage DESC to use more applicable growth forecasts in the future.

Q. DESC DOES NOT APPEAR TO INCLUDE O&M COSTS IN THE ESTIMATE OF MARGINAL COSTS. PLEASE EXPLAIN WHY O&M COSTS SHOULD BE ADDED TO THE MARGINAL DISTRIBUTION CAPACITY COSTS.

A. It is standard practice to include O&M costs in the calculation of marginal capacity costs. The two (2) general approaches are: 1) include O&M costs in the levelization factor (a fixed charge rate or a real economic carrying charge) or 2) add O&M costs as an additional marginal cost line item. DESC has done neither, so O&M should be added.

Q. DO YOU RECOMMEND ANY CHANGES TO THE METHOD DESC USED TO ESTIMATE TRANSMISSION MARGINAL COSTS?

A. Yes. O&M costs should also be added to DESC's transmission marginal capacity cost estimate. I do not recommend a noncoincident demand adjustment be applied to transmission at this time. While DESC also uses system growth for their transmission marginal capacity cost calculations, that is not as problematic as with distribution. The reason is that transmission is likely a largely networked system (compared to the radial distribution system), and the nature of power flow across a network makes the simultaneous peaks more relevant for the need for transmission capacity additions.

Q. DO YOU HAVE SPECIFIC CHANGES FOR THE DEC OR DEP ESTIMATES OF MARGINAL T&D COSTS PROVIDED IN RESPONSE TO THE VOTE SOLAR ET AL DATA REQUEST IN THIS DOCKET?

A. Not at this time. The marginal capacity cost information provided by Duke consisted of simple tables of hard coded values that do not allow investigation of the methodology or underlying data. I do note, however, that the annualization rates that convert the unit cost ($/kw) of T&D expenditures into annual marginal costs ($/kW-year) are dramatically different for the two operating companies. I would expect only small differences in the annualization rates for Duke, so the tariff phase of this docket should allow investigation of the validity of the current values in addition to a review of the other underlying assumptions used by Duke.

INDIRECT ECONOMIC COSTS AND BENEFITS

Q. WHAT OTHER MARGINAL COST COMPONENTS SHOULD BE INCLUDED IN THE EVALUATION OF THE COSTS AND BENEFITS?

A. The list of components from Act 62 is appropriate for direct monetized impacts. However, for the determination of what, if any, cost shift should be supported in order to promote continued solar market activity, indirect economics impacts should also be estimated. These indirect impacts should be included in consideration of the tradeoffs between the goal of eliminating "any cost shift to the greatest extent practicable" and the South Carolina General Assembly's intent to "avoid disruption to the growing market for customer-scale distributed energy resources, but these costs should not be included in the avoided cost framework specifically documented within Commission Order No. 2015-194.

The indirect impacts that are included will depend upon Commission judgement on how they align with State policies, as well as the amount of rigor and the availability of data to allow their estimation. Common indirect economic impacts for consideration may include:

- Greenhouse gas costs attributed to social damage or future abatement. The logic is that given the persistence of CO_2 and similar global warming emissions in the environment, if society is willing to pay X dollars in the future to reduce those emissions, the value of reducing current emissions should be equal to those X dollars in todays discounted dollars.

- Healthcare and Mortality impacts of air emissions. Options for quantification include using models like the US EPA CO-Benefits Risk Assessment (COBRA) model[9] or using values from the July 2019 US EPA *Public Health Benefits per kWh of Energy Efficiency and Renewable Energy in the United States: A Technical Report.*[10] That report estimates a health benefit for solar generation in the Southeast region of between \$0.0164/kWh and \$0.0415/kWh in 2017 dollars.
- Jobs and knock-on economic benefits such as increased expenditures by workers, taxes, and investment. Estimating these impacts would require a full study of potential macroeconomic benefits and costs of customer solar and would likely use a regional macroeconomic model such as REMI or IMPLAN.
    - I believe that in the short-term increased customer solar would likely result in higher economic activity in South Carolina, but in the long term would result in lower economic activity, relative to a scenario with no increased customer solar. The reason for the long term lower economic activity would be from the overall higher spending on electricity due to behind-the-meter solar being more costly than grid resources. The relative size of these short-term and long-term effects, and the size of any ripple effects of the changes throughout the broader state economy, determine the net macroeconomic cost or benefit.

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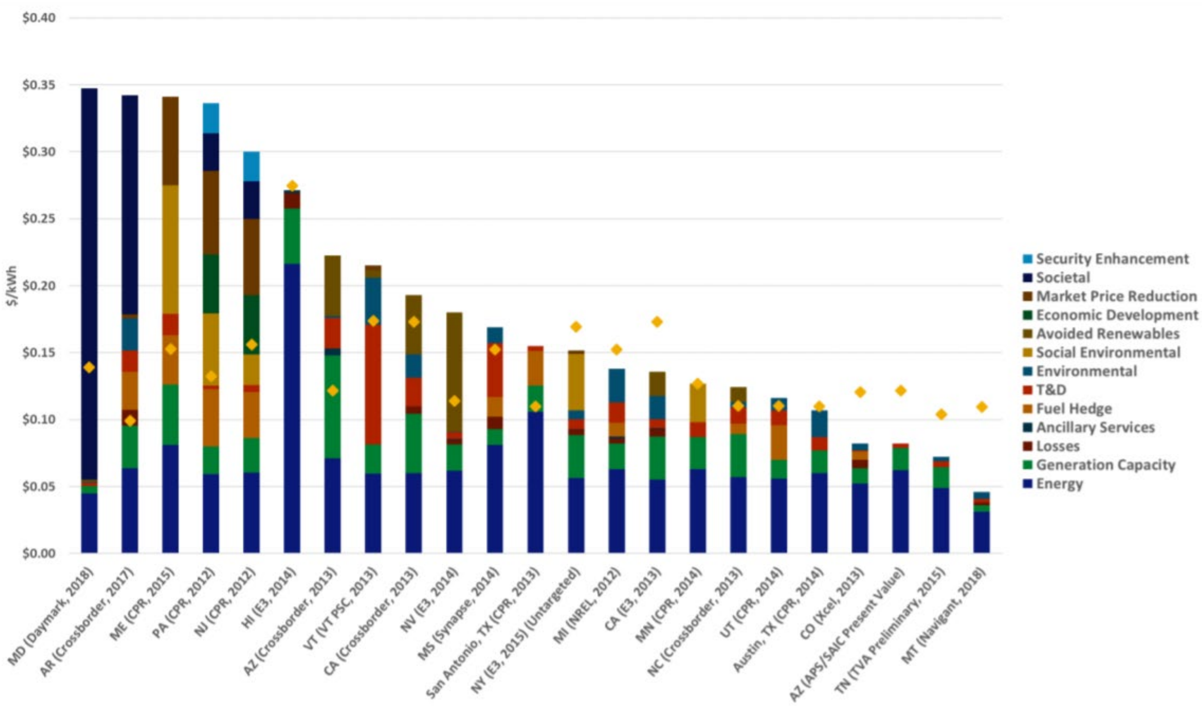
[9] https://www.epa.gov/statelocalenergy/co-benefits-risk-assessment-cobra-health-impacts-screening-and-mapping-tool#4

[10] https://www.epa.gov/sites/production/files/2019-07/documents/bpk-report-final-508.pdf

Lastly, it is worth noting that the value of indirect economic benefits varies significantly across studies, as can be seen in Figure 1, below.

Figure 1: Avoided Cost Benefits Across Different Value of Solar Studies[11]



This figure shows avoided cost benefits by category from different value of solar studies compared to the average residential retail rates in the respective state (the yellow diamonds). In particular, note the significant variance in the "Societal" bar, which shows zero (0) value in a significant number of the studies cited, but compromises the majority of benefit from two (2) studies performed by Daymark in Maryland in 2018, and by Crossborder in Arkansas in 2017. While the studies are not necessarily peer reviewed or subject to regulatory review, the results are useful for illustrating the wide range in possible

[11] See Exhibit BKH-2, pg. 29.

values, which highlights the need for diligence and transparency in the development of any indirect economic impact values to be used in South Carolina.

ASPECTS OF AN IDEAL TARIFF

Q. PLEASE EXPLAIN WHY IT IS IMPORTANT TO UNDERSTAND HOW AVOIDED COST METHODOLOGIES COULD BE USED IN THE DESIGN OF THE SOLAR CHOICE METERING TARIFF.

A. While marginal costs may seem like they should be universal at first glance, the reality is that the methods one uses to derive the marginal costs and the associated assumptions can vary based on the goals the Commission is trying to address. For this reason, I believe it is useful to provide some discussion related to the next generation of a Solar Choice Metering Tariff.

Q. PLEASE EXPLAIN THE GOAL OF THE IDEAL SOLAR CHOICE METERING TARIFF FOR CUSTOMER GENERATORS.

A. An ideal tariff would minimize any cost shift between customers with and without the customer generator technology, while still allowing for customer choice to implement DSM or other usage controls.

Q. PLEASE EXPLAIN THE GENERAL PROCESS FOR CREATING A SOLAR CHOICE METERING TARIFF.

A. The important aspects of rate design in the context of DER are discussed in more detail in the 2018 Report provided in Exhibit BKH-2, but broadly, there are three (3) basic steps to rate design, or to create a tariff. These are:

1) **Determine customer classes**. Classes are groups of similar customers that will be subject to the same default rates. The typical customer classes are residential, commercial (may be further distinguished by small/medium/large), and industrial (very large users). In many jurisdictions there are also classes based on the use of electricity (e.g.: agricultural, streetlighting). The factors considered in defining customers classes are primarily the homogeneity of customer usage and size, although other factors such as customer location and value of service can also be important.
2) **Allocate utility costs to each class**. This typically involves a COS study where the annual costs that a utility needs to pay all obligations and earn a reasonable return are divided into major utility functions (e.g.: production, transmission, distribution, and customer service). The functionalized costs are then classified according to their cost drivers (e.g.: energy usage, demand at the time of the summer peak, maximum class demand, number of accounts). The functionalized and classified costs are then allocated to each class in proportion to the class's cost driver for that function. For example, the cost of a generating plant may be functionalized 100% to production and classified 80% energy and 20% demand. 80% of the plant cost would be allocated to classes based on each class's energy usage, and 20% would be allocated based on each class's demand at the time of the system peak. The final results of the COS study are total costs and average rates for each customer class.

In many cases, for reasons such as rate stability, classes may not have their target revenues set at the levels determined by the COS study allocations. However, even in those cases, the plan would be to transition over time to the COS study allocations unless there were some concern with the accuracy of the study or some policy reason to maintain a deviation.

3) **Design rates to collect class costs.** Once target revenues are set for each class, the final step involves decisions on how to design rates to recover these costs (e.g.: magnitudes and numbers of rate components such as energy prices, time-of-use based energy prices, demand charges, meter charges, standby charges, and customer charges). The final rates will collect the target revenue based on the total usage and the usage characteristics of the entire class. This means that customers with typical or average usage characteristics will have similar bills to one another and pay around the class average rate. However, depending on the rate design, customers that differ substantially from the average usage characteristics may end up subsidizing or being subsidized by other customers in the class. The causes and risks (e.g.: magnitudes on all customers, but especially on economically fragile or disadvantaged segments of the class) of cost shifts should be included in the rate design decision process to ensure that the resulting cost recovery mechanisms are still fair, efficient, and effective.

Q. PLEASE EXPLAIN THE CONCERNS WITH SOLAR AND NON-SOLAR CUSTOMERS RECEIVING THE SAME RATE FOR ENERGY DELIVERED BY THE UTILITY.

A. If the rates for all customers were advanced enough to properly reflect the cost to serve each individual customer, then there would be no problem in using the same rate for customers with or without solar. Advanced rates have energy, demand, and customer charges that are set at levels that reflect the cost to the utility to provide those services.

Also, advanced energy charges will also be differentiated to reflect how production costs vary by season and time of day. Such rates are common for large utility customers such as industrial customers but are sorely lacking for residential and small commercial customers for reasons of rate stability and simplicity. Metering and billing system costs were also a major barrier to using advanced rates for small customers, but recent advancements in metering have removed that barrier in many jurisdictions.

For those customer classes that are not on advanced rates, such as residential customers, using the same rate would introduce large cost shift problems for each solar installation. If the number of solar installs is small relative to the total class population, then the cost shift per customer is small and may allow continued use of the single rate without undue concern. However, in general, I believe that residential customers with solar installed behind the meter are so different in their usage characteristics from non-solar customers that they warrant a different set of rates.

Q. IF A SEPARATE RATE FOR CUSTOMERS WITH SOLAR IS ESTABLISHED, SHOULD A SEPARATE RATE BE ESTABLISHED FOR CUSTOMERS THAT HAVE OTHER DSM PROGRAMS SUCH AS ENERGY EFFICIENCY ("EE")?

A. No, I do not think a separate rate is necessary. The reason for a different rate for solar customers is that their use of electricity from the grid is very different from regular customers. Solar installations add a generation source behind-the-meter that has no relationship to the usage of the host customer. In contrast, customers that conserve energy or install efficient devices still look like other residential customers. To be sure, their usage may be lower, and they may have slightly different usage patterns, but their fundamental usage pattern will not be dramatically different from customers without EE.

Q. PLEASE EXPLAIN THE OTHER BENEFITS TO ESTABLISHING A SEPARATE SOLAR CHOICE METERING TARIFF FOR CUSTOMERS WITH SOLAR SYSTEMS.

A. Establishing a separate rate for customers with solar systems allows for more flexibility in the design of the rates than would be available under a single base rate tariff. It would be a poor outcome to have "the tail wag the dog" and force all residential customers onto advanced rates just to address the cost shift problem of solar customers. By separating the applicability of the tariffs, the Commission retains the flexibility to leave the non-solar customers rate design alone, and design rates that make sense for the solar customers. This could take the form of advanced rates or could even be less advanced if the solar customers are relatively homogenous among themselves. Once the majority of the cost shift is addressed through the establishment of a separate rate (assuming the separate rate collects an appropriate level of revenue), the Commission can then decide whether any cost shift among solar customers (relatively larger versus relatively smaller solar installations) requires use of the advanced rate structure.

Q. PLEASE EXPLAIN THE COMPONENTS OF AN IDEAL SOLAR CHOICE METERING TARIFF DESIGNED TO RECOVER COSTS ALLOCATED TO A SOLAR CUSTOMER?

A. As discussed in more detail in the 2018 Report provided in Exhibit BKH-2,[12] there are tensions inherent in any rate design that seeks to balance sometimes competing objectives, such as balancing economically efficient and complex rates with simpler rates that are more easy to understand, but may not allocate costs to customers on a pure cost-causation basis. The following components are the hallmarks of an ideal Solar Choice Metering Tariff:

1) A flat monthly service charge to recover utility fixed costs related to serving a customer, independent of customer usage;
2) Time varying rates to better provide price signals to customers regarding the utility's variable costs related to energy procurement, and to incentivize customer energy usage patterns to better align with cost causation; and
3) Monthly demand charges to recover the customer's maximum usage of the grid. A variety of mechanisms could be used, such as an average of several peak demand levels within a billing period, a rolling average of daily peak demand, or even a simple size-based demand charge to reflect maximum withdrawals and injections of power into the grid.

Q. PLEASE IDENTIFY THE EQUITY-RELATED ISSUE THE COMMISSION SHOULD CONSIDER IN EVALUATING THE FRAMEWORK FOR THE FUTURE SOLAR CHOICE METERING TARIFFS.

A. The Commission should also consider the distributional impacts of any cost shift. There is a long history in energy efficiency and conservation for utilities to offer special

[12] See Chapter 2, Rate Design.

programs to provide energy efficiency for low income customers. Experience in high NEM states like Hawaii and California show solar being adopted by more affluent residential customers, with the result being that lower income customers bear an unequal burden from any cost shift.

Q. ARE THERE ANY OTHER ISSUES THAT THE COMMISSION SHOULD CONSIDER IN EVALUATING THE FUTURE SOLAR CHOICE METERING TARIFFS?

A. Yes. The Commission should consider the tradeoff between targeting maximal economic efficiency, and the resultant complexity that creates for both utilities and customers, with the benefits of simple rates which increase customer stability and are often more feasible to implement.

Simple rate structure becomes an option only if the solar customers are put into a separate rate class or on a separate tariff (not just a solar specific rider for the exported solar power, but a separate rate for the net energy received from the grid). If set sufficiently high, the separate rate for solar customers can address the majority of cost shift concerns by mitigating the cost shift from solar to non-solar customers. A simple rate (such as one with a small customer charge and only time-of-use energy charges) would still have some cost shifts among solar customers, but those shifts would be smaller because the solar customers would be more homogenous with one another than they are with the non-solar customers.

Q. DO YOU HAVE CONCLUDING REMARKS?

A. Yes. I hope my comments are helpful to the Commission as they consider how to reform NEM rates to compensate customers with solar while at the same time eliminating or minimizing the cost shift burden created by behind-the-meter solar installations. In summary, the Commission should consider the following recommendations in the evaluation of cost and benefits and establishment of a methodology:

1) The term "cost shift" can be interpreted in different ways, so it is important to establish a clear definition of cost shift and understand the implications of the definition.
2) Marginal cost is the appropriate method to estimate the cost shift that is the financial burden shifted to all customers by the installation of solar or other DER.
3) Indirect economic costs and benefits should be estimated through separate analysis to allow for a thorough comparison of any marginal cost-based cost shift to the additional indirect impacts (i.e.: net benefits) of solar or other DER.
4) Embedded COS studies should be conducted to comply with S.C. Code Ann Section 58-40-20(D)(2). The results, however, will not represent the actual cost shift imposed by solar and DER, but a hypothetical cost shift that is relative to a hypothetical embedded cost solar rate that currently exists.
5) Embedded COS studies typically use overly simplistic determinations of peak demands that drive the need for utility capacity investments, so the utility assumptions in the studies used for this docket should be examined carefully.
6) The list of avoided cost components adopted in Commission Order No. 2015-194 is appropriate.

7) Indirect economic costs and benefits should also be evaluated in this docket as they will help inform the appropriateness of adopting Solar Choice Metering Tariffs that may continue cost shifts.
8) Non-zero marginal T&D capacity costs should be included in the marginal cost-based cost shift analysis, but interested parties will need the opportunity to evaluate the marginal cost estimates to eliminate problems such as those identified in the current values.
9) Experience in other jurisdictions shows a tendency for solar to be installed by larger more affluent households. The Commission should therefore consider the cost shift impact on not only the non-solar customers as a whole, but also the non-solar low-income customers in particular.
10) Tariffs that have fixed monthly charge, time varying energy charges, and demand-based charges can be ideal rate design components for a Solar Choice Metering Tariff because customers will be charged based on how the customers impose costs on the utility.
11) Simpler tariffs could also be appropriate Solar Choice Metering Tariffs if those simpler tariffs are designed separate from the non-solar customer rates, are based on the characteristics of solar customers, and are mandatory for solar customers.

Q. WILL YOU UPDATE YOUR DIRECT TESTIMONY BASED ON INFORMATION THAT BECOMES AVAILABLE?

A. Yes. ORS fully reserves the right to revise its recommendations via supplemental testimony should new information not previously provided by the Company, or other sources, becomes available.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

Brian Horii

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ENERGY AND ENVIRONMENTAL ECONOMICS, INC. San Francisco, CA
Senior Partner 1993 – Present

Mr. Horii is one of the founding partners of Energy and Environmental Economics, Inc. (E3). He is a lead in the practice areas of Resource Planning; Energy Efficiency and Demand Response; Cost of Service and Rate Design; and acts as a lead in quantitative methods for the firm. Mr. Horii also works in the Energy and Climate Policy, Distributed Energy Resources, and regulatory support practice areas. He has testified and prepared expert testimony for use in regulatory proceedings in California, South Carolina, Texas, Vermont, British Columbia, and Ontario, Canada. He designed and implemented numerous computer models used in regulatory proceedings, litigation, utility planning, utility requests for resource additions, and utility operations. His clients include BC Hydro, California Energy Commission, California Public Utilities Commission, Consolidated Edison, El Paso Electric Company, Hawaiian Electric Company, Hydro Quebec, Minnesota Department of Commerce, NYSERDA, Orange and Rockland, PG&E, Sempra, Southern California Edison, and South Carolina Office of Regulatory Staff.

Resource Planning:

- Authored the Locational Net Benefits Analysis (LNBA) tool used by California IOUs to evaluate the total system and local benefit of distributed energy resources by detailed distribution subareas
- Created the software used by BC Hydro to evaluate individual bids and portfolios tendered in calls for supplying power to Vancouver Island, demand response from large customers, and new clean power generation
- Designed the hourly generation dispatch and spinning reserve model used by El Paso Electric to simulate plant operations and determine value-sharing payments
- Evaluated the sale value of hydroelectric assets in the Western U.S.
- Simulated bilateral trading decisions in an open access market; analyzed market segments for micro generation options under unbundled rate scenarios; forecasted stranded asset risk and recovery for North American utilities; and created unbundled rate forecasts
- Reviewed and revised local area load forecasting methods for PG&E, Puget Sound Energy, and Orange and Rockland Utilities

Energy Efficiency, Demand Response, and Distributed Resources:

- Author of the “E3 Calculator” tool used as the basis for all energy efficiency programs evaluations in California since 2006
- Independent evaluator for the development of locational avoided costs by the Minnesota electric utilities
- Consulted on the development of the NEM 2.0 Calculator for the CPUC Energy Division that was used by stakeholders in the proceeding as the common analytical framework for party positions; also authored the model’s sections on revenue allocation that forecast customer class rate changes over time, subject to changes in class service costs

- Co-author of the avoided cost methodology adopted by the California CPUC for use in distributed energy resource programs since 2005
- Principal consultant for the California Energy Commission's Title 24 building standards to reflect the time and area specific value of energy usage reductions and customer-sited photovoltaics and storage
- Principal investigator for the 1992 EPRI report *Targeting DSM for Transmission and Distribution Benefits: A Case Study of PG&E's Delta District*, one of the first reports to focus on demand-side alternatives to traditional wires expansion projects
- Provided testimony to the CPUC on the demand response cost effectiveness framework on behalf of a thermal energy storage corporation

Cost of Service and Rate Design:

- Designed standard and innovative electric utility rate options for utilities in the U.S., Canada, and the Middle East
- Principal author of the *Full Value Tariff and Retail Rate Choices* report for NYSERDA and the New York Department of Public Staff as part of the New York REV proceeding
- Developed the rate design models used by BC Hydro and the BCUC for rate design proceedings since 2008
- Principal author on marginal costing, ratemaking trends and rate forecasting for the California Energy Commission's investigation into the revision of building performance standards to effect improvements in resource consumption and investment decisions
- Consulted to the New York State Public Service Commission on appropriate marginal cost methodologies (including consideration of environmental and customer value of service) and appropriate cost tests
- Authored testimony for BC Hydro on Bulk Transmission Incremental Costs (1997); principal author of B.C. Hydro's System Incremental Cost Study 1994 Update (With Regional Results Appendix)
- Performed detailed market segmentation study for Ontario Hydro under both embedded and marginal costs
- Testified for the South Carolina Office of Regulatory Staff on SCANA marginal costs
- Taught courses on customer profitability analysis for the Electric Power Research Institute
- Other work has addressed marginal cost-based revenue allocation and rate design; estimating area and time specific marginal costs; incorporating customer outage costs into planning; and designing a comprehensive billing and information management system for a major energy services provider operating in California

Transmission Planning and Pricing:

- Designed a hydroelectric water management and renewable integration model used to evaluate the need for transmission expansion in California's Central Valley
- Developed the quantitative modeling of net benefits to the California grid of SDG&E's Sunrise Powerlink project in support of the CAISO's testimonies in that proceeding
- Testified on behalf of the Vermont Department of Public Service on the need for transmission capacity expansion by VELCO
- Determined the impact of net vs. gross billing for transmission services on transmission congestion in Ontario and the revenue impact for Ontario Power Generation

- Authored numerous Local Integrated Resource Planning studies for North American utilities that examine the cost effectiveness of distributed resource alternatives to traditional transmission and distribution expansions and upgrades
- Developed the cost basis for BC Hydro's wholesale transmission tariffs
- Provided support for numerous utility regulatory filings, including testimony writing and other litigation services

Energy and Climate Policy:

- Author of the E3 "GHG Calculator" tool used by the CPUC and California Energy Commission for evaluating electricity sector greenhouse gas emissions and trade-offs
- Primary architect of long-term planning models evaluating the cost and efficiency of carbon reduction strategies and technologies
- Testified before the British Columbia Public Utilities Commission on electric market restructuring

PACIFIC GAS & ELECTRIC COMPANY San Francisco, CA
Project Manager, Supervisor of Electric Rates 1987-1993

- Managed and provided technical support to PG&E's investigation into the Distributed Utilities (DU) concept; projects included an assessment of the potential for DU devices at PG&E, an analysis of the loading patterns on PG&E's 3000 feeders, and formulation of the modeling issues surrounding the integration of Generation, Transmission, and Distribution planning models
- As PG&E's expert witness on revenue allocation and rate design before the California Public Utilities Commission (CPUC), was instrumental in getting PG&E's area-specific loads and costs adopted by the CPUC and extending their application to cost effectiveness analyses of DSM programs
- Created interactive negotiation analysis programs and forecasted electric rate trends for short-term planning

INDEPENDENT CONSULTING San Francisco, CA
Consultant 1989-1993

- Helped develop methodology for evaluating the cost-effectiveness of decentralized generation systems for relieving local distribution constraints; created a model for determining the least-cost expansion of local transmission and distribution facilities integrated with area-specific DSM incentive programs
- Co-authored *The Delta Report* for PG&E and EPRI, which examined the targeting of DSM measures to defer the expansion of local distribution facilities

Education

Stanford University Palo Alto, CA
M.S., Civil Engineering and Environmental Planning 1987

Stanford University — Palo Alto, CA

B.S., Civil Engineering — 1986

Citizenship

United States

Refereed Papers

1. *Woo, C.K., I. Horowitz, B. Horii, R. Orans, and J. Zarnikau (2012) "Blowing in the wind: Vanishing payoffs of a tolling agreement for natural-gas-fired generation of electricity in Texas," The Energy Journal, 33:1, 207-229.*
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8. *Woo, C.K., I. Horowitz, B. Horii and R. Karimov (2004) "The Efficient Frontier for Spot and Forward Purchases: An Application to Electricity," Journal of the Operational Research Society, 55, 1130-1136.*
9. *Woo, C. K., B. Horii and I. Horowitz (2002) "The Hopkinson Tariff Alternative to TOU Rates in the Israel Electric Corporation," Managerial and Decision Economics, 23:9-19.*
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11. *Chow, R.F., Horii, B., Orans, R. et. al. (1995), Local Integrated Resource Planning of a Large Load Supply System, Canadian Electrical Association.*
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Discussion of South Carolina Act 236: Version 2.0

December 2018

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Table of Contents

Glossary/List of Acronyms

- **Act 236 (Distributed Energy Resources Program Act):** legislation passed in 2014, meant to address renewable energy development in South Carolina. The legislation's three sections address third-party leasing, net energy metering, and utility cost recovery for renewable energy procurement and incentives.
- **2015 Settlement Agreement:** In 2015, the South Carolina Public Service Commission approved the Settlement Agreement in Order 2015-194. The Agreement included the methodology to be used to calculate the value of DER, that the 1:1 NEM rate would be preserved until January 1, 2021, and that the difference between the value of DER generation (as calculated using the NEM methodology) and the 1:1 NEM rate would be treated as a DER program expense and collected through the fuel clause, not through base rates.

- **DEC**: Duke Energy Carolinas
- **DEP**: Duke Energy Progress
- **DERs**: Distributed Energy Resources
- **E3**: Energy and Environmental Economics, Inc.
- **IOU**: Investor-Owned Utility
- **MW**: Megawatt
- **NEM**: Net Energy Metering
- **ORS**: Office of Regulatory Staff
- **PSC**: Public Service Commission
- **SCE&G**: South Carolina Electric & Gas
- **SRNL**: Savannah River National Laboratory

Executive Summary

Continuing in the collaborative framework that helped to produce South Carolina's landmark Distributed Energy Resources Program Act of 2014 (Act 236),[1] multiple stakeholders in the state's energy sector met regularly between June and December of 2018 to discuss the future of distributed energy resources (DERs) in South Carolina as part of an "Act 236: Version 2.0" process. The group was convened by the Office of Regulatory Staff (ORS) and facilitated by the ORS Energy Office (Energy Office). Stakeholders included representatives from private and public electric utilities and cooperatives, renewable energy developers and solar industry groups, environmental and environmental justice organizations, consumer advocates, large energy users, and researchers from the Savannah River National Laboratory.

Energy and Environmental Economics, Inc. (E3)[2] was retained as an independent consultant by ORS to participate in these meetings, conduct analyses, and produce this report summarizing relevant key issues for a potential version 2.0 of Act 236. This report aims to highlight the topics stakeholders addressed in the meetings, note areas of significant disagreement, provide context and perspective as to how various issues interact with and influence one another, and describe how other states and jurisdictions around the country have approached similar situations. <u>The report is not meant to be prescriptive</u> regarding how South Carolina should address DERs going forward; rather, <u>this report is primarily meant to be informative to policymakers</u> as well as other interested parties in order to guide future decision-making. Further, we would like to acknowledge that many stakeholders provided in-depth and thoughtful comments and edits to this report as it was being drafted. To the extent possible, E3 incorporated this important feedback as we developed the final draft of this report.

Many wide-ranging and far-reaching topics were discussed, debated, and addressed by stakeholders during the Act 236: Version 2.0 process. It is important to note that this diverse group of stakeholders do not agree on all topics, and further, strongly disagree on some issues. Throughout the report, we explicitly highlight and discuss these areas of contention in order to reflect the process and stakeholder views as faithfully as possible.

The section below summarizes both the key takeaways and major areas of contention, organized by report section.

[1] http://www.scstatehouse.gov/sess120_2013-2014/bills/1189.htm
[2] www.ethree.com

Rate Design

Key Takeaways: DER compensation is an entrenched issue within the larger set of general rate design concerns. A key challenge in designing effective rates for DERs is to address DER-specific issues without adversely impacting unrelated rate considerations. No perfect intersection exists between the "right" retail rate and the "best" type of DER compensation; balancing at-times competing interests such as utility/DER revenue certainty, accurately-valued DER compensation, and customer equity concerns is often challenging, and there is no single, correct approach. Compromise and balance are needed for equitable and sustainable rate design that fairly compensates all resources.

Areas of Contention:

- There is no agreement on how rate design should evolve in South Carolina, either as a DER compensation mechanism or more broadly for all customers.
- Some stakeholders feel that increasing customer fixed charges is not an appropriate response to cost shifting.
- Stakeholders do not agree whether DER customers should be considered as distinct from non-DER customers for the purposes of ratemaking.

Customer-Scale Installations and the Value of Solar

Key Takeaways: The value assigned to DERs has a fundamental impact on the magnitude of any cost shift from net metering of these resources. Different jurisdictions have taken a wide variety of approaches to DER valuation, including assigning amounts to components currently considered to have a zero-value in South Carolina.

Areas of Contention:

- Avoided cost values have been contested every year since the passage of Act 236.
- Stakeholders disagree as to whether the Act 236 2.0 process is the correct forum for discussing avoided costs, given that the South Carolina General Assembly has already granted the PSC authority over the calculation methodology.
- Some stakeholders feel there are reasonable approaches to updating certain components of the NEM methodology, while others disagree and argue doing so is not cost-effective.

Cost Shift Report

Key Takeaways: Using the methodology selected for this report, the estimated cost shift from net energy metering is substantially higher than previous assessments, with the change driven predominantly by increases in expected customer-scale solar installations and decreases in avoided cost values. No retail rate adjustments have been made in the cost shift analysis with regard to the outcome of the VC Summer proceeding.

Areas of Contention:

+ Stakeholders disagree as to whether NEM should be considered a cost shift, since this is predicated on utilities being permitted to recover the cost of lost retail revenues.
+ Stakeholders disagree about the methodology used to calculate the cost shift and the calculated avoided cost values, which are a key input into the calculation.

Low-to-Moderate Income Customers

Key Takeaways: Energy bills represent a larger portion of low-to-moderate income (LMI) customers' incomes than they do for other customers. Current LMI energy assistance programs in South Carolina serve a relatively small portion of the LMI population and are largely funded by federal grants. Other states have taken various approaches to providing energy bill assistance to LMI customers, any of which could be applied in South Carolina if desired.

Areas of Contention:

+ While all stakeholders support LMI customer assistance, there is disagreement over the appropriate approach and whether this stakeholder process is the best opportunity for action, given that LMI equity issues extend beyond the focus of this group.

Commercial and Industrial Renewable Energy Programs

Key Takeaways: Green Tariff programs internalize incremental costs and avoid the potential for cost shifting to non-participating customers, with various program structures allowing for customization to specific state scenarios.

Areas of Contention:

+ Some stakeholders note that proposed Green Tariff programs in South Carolina will not be available to all customers given current eligibility criteria.

PURPA, Interconnection, and Utility-scale Resources

Key Takeaways: South Carolina may want to consider further review of its avoided cost calculations. Several key process changes could likely improve the interconnection process of utility-scale projects, especially as North Carolina solicits large amounts of new solar and South Carolina will need to actively ensure equity in its interconnection process.

Areas of Contention:

+ Stakeholders disagree about whether the current avoided cost methodology accurately reflects the true value of non-utility generation resources.

Areas for Further Consideration

Key Takeaways: Stakeholders in this process have made progress on several important questions regarding South Carolina's near-term energy future. Considerable ongoing attention is needed to design a robust and dynamic electric system that can take advantage of new technologies while minimizing customer costs. Several key areas to consider in this ongoing discussion include the potential for holistic rate design, how to best modernize the grid, and the design of a comprehensive and truly integrated resource planning process.

E3 appreciates the opportunity to have participated in this important process. We hope this report reflects stakeholders' contributions and the diversity of their views on the issues and complexities facing South Carolina's energy sector. We also hope this report informs South Carolina's policymakers as they grapple with these important issues going forward.

1 Introduction

Continuing in the collaborative framework that helped to produce South Carolina's landmark Distributed Energy Resources Program Act of 2014 (Act 236),[3] multiple stakeholders in the state's energy sector met regularly between June and early December of 2018 to discuss the future of distributed energy resources (DERs) in the Palmetto State as part of an "Act 236: Version 2.0" process. The group was convened by the Office of Regulatory Staff (ORS) and facilitated by the Energy Office division of ORS. Stakeholders included representatives from private and public electric utilities and cooperatives, renewable energy developers and solar industry groups, environmental and environmental justice organizations, consumer advocates, large energy users, and researchers from the Savannah River National Laboratory.

Energy and Environmental Economics, Inc. (E3)[4] was retained as an independent consultant by ORS to participate in these meetings, conduct an analysis of the current cost shift attributable to the expansion of DERs in South Carolina as required by Act 236, and produce this report summarizing the relevant key issues for a potential version 2.0 of Act 236. This report aims to highlight the topics stakeholders addressed in the meetings, note areas of significant disagreement, provide context and perspective as to how various issues interact with and influence one another, and describe how other states and jurisdictions around the country have approached similar situations. <u>The report is not meant to be prescriptive</u> with regard to how South Carolina should address DERs going forward; rather, <u>this report is primarily meant to be informative to policymakers</u> as well as other interested parties in order to guide future decision-making.

E3 would like to thank the stakeholders who provided data for this report for their rapid and informative responses to our requests. In addition, we would like to thank the many stakeholders that provided in-depth and thoughtful comments and suggested edits to this report as it was being drafted. To the extent possible, E3 incorporated this important feedback as we developed the final draft of this report.

The report has nine sections which are generally organized around the major Act 236: Version 2.0 topics as follows:

1. The **<u>Introduction</u>** provides background and context for the report.

2. **<u>Rate Design</u>** addresses the topic of electric retail rate design in general and in the specific context of DERs, including solar.

3. **<u>Customer-Scale Installations and the Value of Solar</u>** addresses topics related to installations at the customer scale and discusses different approaches to DER valuation.

[3] http://www.scstatehouse.gov/sess120_2013-2014/bills/1189.htm
[4] www.ethree.com

4. **Cost Shift Report** is an analysis mandated by Act 236 that provides an estimate of the "cost shift" or incentive associated with the net energy metering (NEM) program as well as the other incremental costs of each of the state's large investor-owned utilities' (IOUs) DER programs.

5. **Low-to-Moderate Income Customers** addresses topics associated with electric customers with low-to-moderate incomes in South Carolina.

6. **Commercial and Industrial Renewable Energy Programs** addresses topics associated with renewable energy programs for larger customers like commercial businesses and industrial facilities.

7. **PURPA, Interconnection, and Utility-scale Resources** addresses topics associated with larger scale installations of renewable resources such as utility-scale solar.

8. **Areas of Further Consideration** briefly addresses topics that may be relevant for further consideration that were outside the scope of the stakeholder process that generated this report.

9. The **Appendix** further expands certain topics from the main body of this report and provides additional information that readers may find relevant.

1.1 Act 236: The Distributed Energy Resources Program Act of 2014

The Distributed Energy Resources Program Act of 2014, better known simply as Act 236, aimed to "promote the establishment of a reliable, efficient, and diversified portfolio of distributed energy resources" for the State of South Carolina."[5] To further the goal of promoting DERs, Act 236 authorized the state's three largest investor-owned utilities (IOUs) to propose DER programs for which they could receive cost recovery. The state's three largest IOUs are Duke Energy Carolinas, LLC (DEC); Duke Energy Progress, LLC (DEP); and South Carolina Electric & Gas Company (SCE&G)[6]. Act 236 further required the Public Service Commission of South Carolina (PSC or "Commission") to establish a valuation methodology for net energy metering (NEM) to be used in computing the value of DER. The IOUs were required to make NEM available to customer-generators on a first-come, first-served basis until aggregate NEM capacity reached two percent of the previous five-year average of the utility's retail peak demand within the state.[7] Act 236 also permitted the leasing of solar systems in South Carolina for the first time, initiated a process for revising the state's interconnection standards, and directed the electric cooperatives to study and adopt net metering policies.

[5] S.C. Code Ann. § 58-39-110

[6] See ORS data on the number of customers per utility in South Carolina: http://energy.sc.gov/node/3072

[7] "Status Report on Distributed Energy resource and Net Energy Metering Implementation." South Carolina Office of Regulatory Staff. July 2017.

This report defines DERs consistent with the definition used in Act 236, as "demand- and supply-side resources that can be deployed throughout the system of an electrical utility to meet the energy and reliability needs of the customers served by that system, including, but not limited to, renewable energy facilities, managed loads (including electric vehicle charging), energy storage, and other measures necessary to incorporate renewable generation resources, including load management and ancillary services, such as reserves, voltage control, and reactive power, and black start capabilities."[8] As a practical matter, solar photovoltaics have been the primary renewable energy resource installed pursuant to the Act 236 DER programs to date.

1.1.1 PROGRESS TO DATE

Since the passage of Act 236, the penetration of renewable energy in South Carolina has increased dramatically. The Energy Office reports that installed solar capacity in the state rose from just over 5 megawatts (MW) in July 2015 to nearly 470 MW in July 2018, an increase of over 9,000% in three years.[9]

This capacity increase has been driven by the utility-specific goals set out in Act 236, along with other factors such as the Public Utility Regulatory Policies Act of 1978 (PURPA), the federal Investment Tax Credit for solar, state tax credits, utility incentives, and declining costs for renewable energy. Figure 1 and Table 1 provide an overview of the three large IOUs' progress toward their respective Act 236 goals as of October 2018.

[8] https://www.scstatehouse.gov/sess120_2013-2014/bills/1189.htm
[9] Exact figures: 5.106 MW-AC in 2015 and 469.228 MW-AC in 2018. http://energy.sc.gov/node/3079

Figure 1. Act 236 Progress to Date

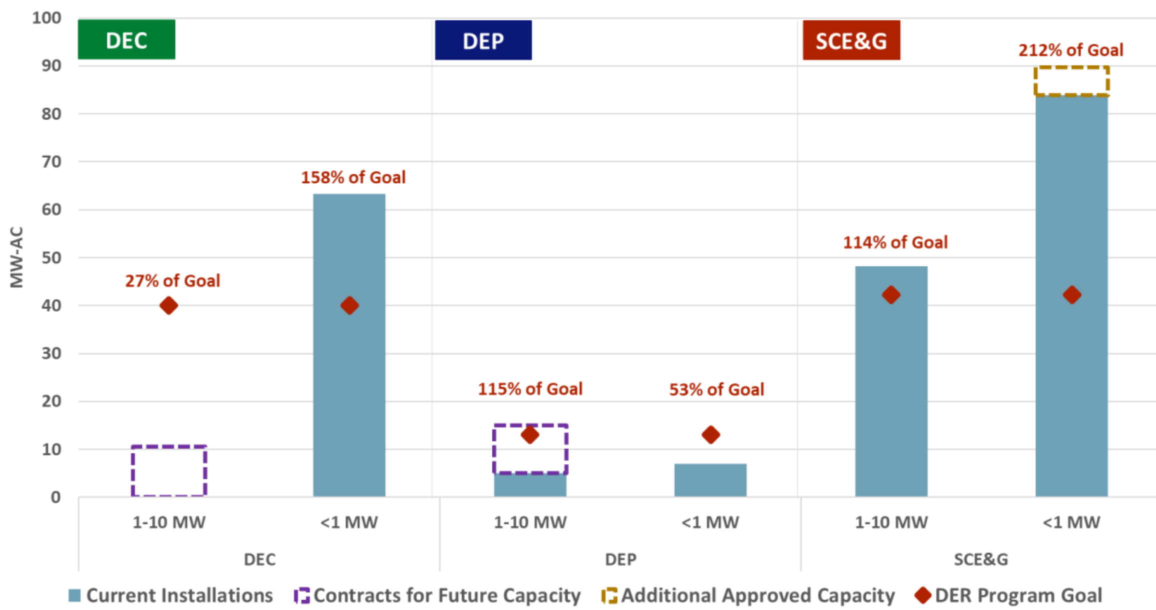


Table 1. Act 236 Progress to Date

Utility	Scale (MW-AC)	DER Program Goal* (MW-AC)	Current Installations (MW-AC)	Additional Approved Capacity (MW-AC)	Contracts for Future Capacity	Goal Attainment**
DEC	1-10 MW	40.0	0.0	N/A	10.6	27%
	<1 MW	40.0	63.3	0.0	N/A	158%
DEP	1-10 MW	13.0	5.0	N/A	10.0	115%
	<1 MW	13.0	6.9	0.0	N/A	53%
SCE&G	1-10 MW	42.3	48.2	N/A	0.0	114%
	<1 MW	42.3	83.9	5.8	N/A	212%

*Act 236 established goals for utility-scale systems (1-10 MW) and customer-scale systems (≤ 1 MW). Of the customer-scale systems, the Act includes a requirement that at least 25% of the total capacity must come from systems ≤ 20 kW.

**Goal Attainment includes Contracts for Future Capacity and Additional Approved Capacity, for the customer-scale and utility-scale categories, respectively.

The rapid development of distributed solar, perhaps spurred by very generous incentives, led to DEC reaching its required NEM target for customers with systems smaller than 1 MW in July 2018 and helped to prompt the introduction of legislation to increase the "cap" on net energy metering.[10] This, in turn, led to the reconvening and expansion of the stakeholder group that originally collaborated on Act 236 and the Commission proceedings implementing the Act. While many energy resource issues have been discussed in the stakeholder meetings over the past several months, the temporary, limited extension of the DEC NEM program was necessary to allow a collaborative process to continue.

As a result of this collaboration, on September 19, 2018, the PSC granted DEC's petition to extend the existing NEM program. The program originally closed to new applicants on August 1, 2018 but was extended to a new date of March 15, 2019. As this issue had been perceived as one of the most pressing by some members of the stakeholder group, this interim fix allowed for discussion of longer-term solutions to the more fundamental questions raised by the increasing development of DERs in South Carolina.

1.1.2 EMPLOYMENT TRENDS

Surveys suggest that employment in the solar industry has grown as a result of the passage of Act 236. Informed by multiple surveys of solar installers conducted between 2014 and 2017, researchers at Savannah River National Lab (SRNL) identified several trends over the past few years. The majority of solar installers operating in South Carolina (71%) began working in the state in 2014 or later, with fully one third of responding companies having begun operation in the state in 2015 when Act 236 went into effect, suggesting that the legislation directly helped to catalyze the local industry.[11] Furthermore, solar installers' service territories have increased over the past several years, and many firms now operate in neighboring states more often. In 2015, 40% of survey respondents only operated in South Carolina, whereas in 2017, 100% of survey respondents also reported serving other states.[12]

A separate estimate of state employment in solar comes from the Solar Foundation, which reports that in 2017 South Carolina employed 2,829 people in this industry across 71 firms.[13] This represents a 2.1% year-over-year increase in the state's solar employment (in line with growth in the state's economy), despite a national solar industry contraction of 3.8% over the same period. Notably, in 2016, state solar employment rose 57.2% over 2015. In the 2017 reporting, South Carolina solar job growth specifically came from increases in installation, sales, and distribution roles, which were partially offset by decreases in manufacturing and project development positions.

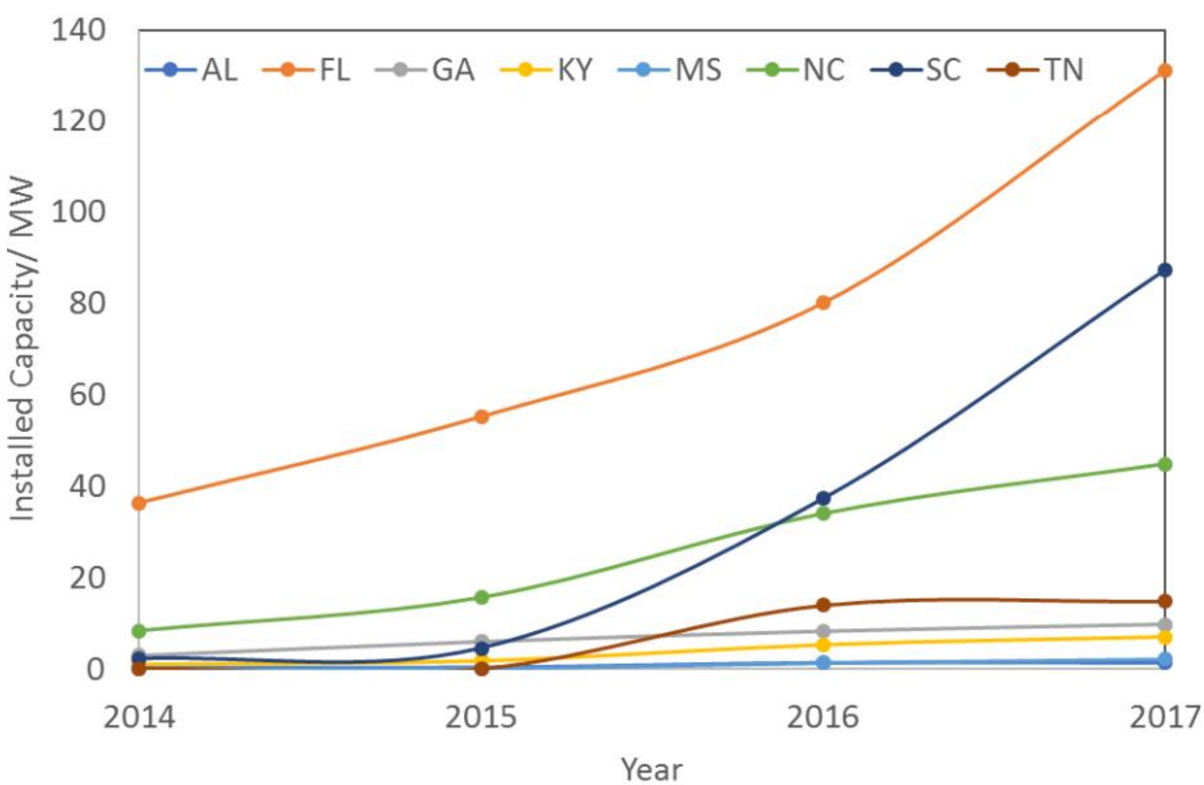
Utility stakeholders note that the electricity sector also employs thousands of people in South Carolina, and growth in the solar industry may cause reductions in direct employment by utilities and indirect employment throughout utility supply chains.

[10] H. 4421 failed to pass the South Carolina House of Representatives, and the net metering extension was removed from H. 4950 in the budget conference committee process.
[11] "2016 End of Year South Carolina PV Soft Cost and Workforce Development." Savannah River National Laboratory. Elise Fox et al. August 2017.
[12] "South Carolina Solar Development - Tracking the Effects of Act 236 (2014-2017)." Savannah River National Laboratory. Elise Fox et al. May 2018.
[13] "Solar Jobs Census 2017: South Carolina." The Solar Foundation. https://www.thesolarfoundation.org/solar-jobs-census-factsheet-2017-SC/

1.2 Solar in the Southeast

Since 2015, South Carolina has achieved significant growth in solar capacity, most notably in the residential sector. Relative to seven other Southeastern states, South Carolina has the second most installed residential solar capacity (see Figure 2). SRNL researchers note that South Carolina has installed more residential capacity than either Georgia or North Carolina, despite these states having roughly twice the population.[14] The U.S. Energy Information Administration reports that as of year-end 2017, South Carolina had more net metering capacity installed than Alabama, Georgia, Kentucky, Mississippi, North Carolina, and Tennessee combined.[15,16]

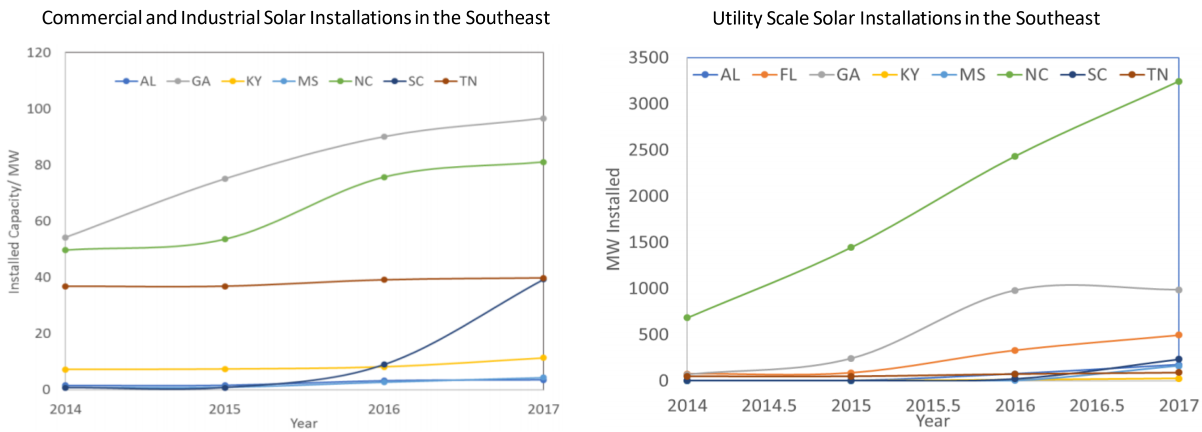
Figure 2. Residential Solar Installations in the Southeast[14]



Solar installations on commercial-, industrial-, and utility-scales have also increased in recent years, although South Carolina does not stand out in the region as significantly at these scales as it does in the residential sector. Figure 3 depicts South Carolina's installations at these scales, relative to other Southeastern states.

[14] "Solar in the Southeast." Savannah River National Laboratory. Elise Fox et al. http://energy.sc.gov/files/SRNL-MS-2018-00114.pdf
[15] Energy Information Administration, Form EIA-861M. October 29, 2018. https://www.eia.gov/electricity/data/eia861m/#netmeter
[16] For reference, the US Census Bureau Population Division estimates the populations of the states highlighted in Figures 2, 3 and 4 as follows (in millions of people): AL: 4.9, FL: 21.0, GA: 10.4, KY: 4.5, MS: 3.0, NC: 10.3, SC: 5.0, TN: 6.7.

Figure 3. Larger-Scale Solar Installations in the Southeast[14]



1.3 Areas of Contention and Disagreement

The introduction to this report would not be complete without acknowledging that the diverse group of stakeholders involved in the Act 236: Version 2.0 process do not agree on all topics, and further, strongly disagree on some issues. While throughout the report we highlight and discuss these areas of contention, here we note several key points of disagreement to introduce the dialogue that took place throughout the stakeholder group's discussions.

- **Rate design**: Stakeholders disagree whether electricity rate structures should be changed in some fashion in response to the growth in DERs, including how rates would change (if at all) for non-DER customers. Additionally, within the group there is a lack of consensus as to the appropriateness of existing cost recovery mechanisms utilized in South Carolina.
- **Value of DERs / Value of Solar**: While South Carolina has an established methodology for calculating the value of DERs, including solar, the stakeholder group exhibits divergent views as to whether this methodology is being implemented in a reasonable fashion by the utilities, despite the approval of the Public Service Commission. This disagreement extends to the derivation of avoided cost values, which are the key inputs to the DER valuation methodology.
- **NEM Cost Shift**: The stakeholder group fundamentally disagrees whether net energy metering should be considered a cost shift, especially given the unique nature of South Carolina IOUs recovering lost retail revenues through the rate rider implemented in Act 236.
- **PURPA, Interconnection and Utility-scale Resources**: As in discussions of the value of DERs, stakeholders disagree whether the current avoided cost methodology accurately reflects the true value of non-utility generation resources.

2 Rate Design

Key Takeaways

- DER compensation is an **entrenched issue** within the larger set of general rate design concerns. A key challenge in designing effective rates for DER customers is to address DER-specific issues without adversely impacting unrelated rate considerations.
- **No perfect intersection exists** between the "right" retail rate and the "best" type of DER compensation. Balancing at-times competing interests such as utility/DER revenue certainty, accurately-valued DER compensation, and customer equity concerns is often challenging, and there is no single, correct approach.
- As demonstrated through the preceding two concepts, **compromise and balance are needed** for equitable and sustainable rate design which fairly compensates all resources.

Areas of Contention

- There is no agreement on how rate design should evolve in South Carolina, either as a DER compensation mechanism or more broadly for all customers.
- Some stakeholders feel that **increasing** customer **fixed charges** is **not an appropriate method to address cost shifting**.
- Stakeholders do not agree **whether DER customers** should be considered as **distinct or separate from non-DER customers for the purposes of ratemaking.**

2.1 The Bonbright Principles

In 1961 James Bonbright published *Principles of Public Utility Rates*,[17] and the framework he put forth has since served as the industry standard by which utility rates are evaluated. The Bonbright principles can be summarized as follows:

[17] "Principles of Public Utility Rates." James C. Bonbright. http://media.terry.uga.edu/documents/exec_ed/bonbright/principles_of_public_utility_rates.pdf

- **Effectiveness**: Rates should recover the total revenue requirement under a fair return standard.
- **Equity**: Rates should be set such that there is fair apportionment of costs among customers.
- **Efficiency**: Rates should promote the efficient use of energy or other services through price signals that reflect utility costs.
- **Customer acceptance**: Rates should be designed such that they are relatively easy and straightforward for customers to understand.
- **Implementation**: Rates should be practical and cost-effective for utilities to implement.
- **Stability**: Customers' rates and bills should remain relatively stable to limit the adverse effects of unexpected changes.

While each of these principles is an important component of the rate design process, there are various tensions inherent among them, and they are continually debated and reexamined in different jurisdictions. Perhaps most notably, the principle of promoting economic efficiency in rates can increase their complexity as well as lead to customer equity issues. However, deviation from economically efficient rates prevents allocation of costs to customers on a pure "'cost-causation" basis. Finding the appropriate balance among these principles therefore requires some level of compromise and trade-offs in rate design.

Utility costs are generally identified as being customer-, demand-, or energy-related. Generally, customer- and demand-related charges are fixed, while energy-related charges are volumetric. Fixed customer-related costs do not vary with consumption or the customer's maximum usage; these include costs for billing, metering, extension of service onto the customer's property, and in many cases a portion of the distribution grid investment required to deliver electricity across the grid to the customer's site. Fixed, demand-related costs are incurred to serve the customer's maximum electrical need and include, for example, generation, transmission, and distribution costs necessary to ensure that adequate electricity resources are always available when required by consumers. Energy-related costs (volumetric costs, which vary based on energy usage) are incurred based upon how much electricity is consumed, rather than when it is consumed and include fuel and other related costs that are only incurred at the time electricity is consumed by the customer.

Historically, technical limitations on metering and billing systems have resulted in a large portion of utility's fixed costs typically being recovered through volumetric rates, especially for residential and small commercial customers, even though these costs are fixed and not variable with volumetric sales. This type of rate design advances Bonbright's principles of efficiency, by sending a marginal price signal to reduce system costs over time; customer acceptance, because differences in usage are easily understood; and implementation, because metering infrastructure for smaller customers has historically counted volumetric usage. Balanced against these principles, volumetric pricing leads to an inherent shift of cost recovery for sunk fixed costs in current rates where customers using more electricity than their class average pay more than the costs they impose on the utility, while customers using less than average pay less than their true cost to serve.

2.2 Cost Allocation and Cost Shifting

One long-recognized effect of balancing the various Bonbright principles is that some customers end up paying more or less than the average bill for a customer in their class. In some contexts, this can be termed "cost shifting," although nearly every customer pays more or less than the average, often partly in an acknowledged effort to advance public policy.

For instance, rural customers often cost more to serve than urban customers because more infrastructure is required to distribute electricity to less dense populations. Utilities generally charge rural and urban customers the same rate, however, in part to advance Bonbright's principles of equity and customer acceptance, and in part for other public policy reasons, such as a recognition of the interdependence of rural and urban economies.

Another example, particularly in jurisdictions with many all-electric homes like South Carolina, is that some customers use electricity for space and water heating, while others use gas.[18] For instance, SCE&G has approximately 362,000 gas customers and 717,000 electric customers. The all-electric customers, on average, use more electricity and have higher electric bills, while the natural gas customers use less. The all-electric residential customers pay more for fixed costs through volumetric rates; this is usually deemed acceptable, rather than being referenced as a "cost shift." Instead, the different levels of fixed cost recovery are essentially "averaged" within rates to promote fairness, acceptance, and simplicity, and these large groups of customers are generally charged the same electric rates.

In order to properly allocate costs, the characteristics of the class must be defined. During a rate case, the PSC approves the amount of fixed costs to allocate to the class in rates by considering data presented, such as the total usage of the class during an annual peak hour for the system as a whole or the usage of the class during its own annual peak hour. The cost of power plants, for instance, will generally be allocated partly on the total system peak and the cost of distribution infrastructure on the class peak. In general, a similar examination of data relevant to ratemaking is needed in order to separate a group of customers into a new class. That new class of ratepayers will then generally have different base rates than other classes. When the disparate treatment of a group of customers is proposed, public service commissions must decide whether the data available show that the size and characteristics of a proposed new grouping of the customers can be fairly said to merit the creation of a new class, as a practical matter and without undue discrimination to either the rate class ratepayers or to ratepayers as a whole.

As a general matter, once costs are allocated to a class, utilities and Commissions must decide how to design rates. The costs presented during the rate case generally derive from a specific year, called the "test year." The ongoing costs of providing service, however, evolve over time. One objective of rate

[18] Other examples include states that offer reduced volumetric rates for customers with medical conditions or residents with incomes below a certain threshold. These rate reductions are financed through higher rates for other customers. An additional example raised is the cost shift caused by customers with second homes, who do likely not pay the average bill for the second home if it does not consume as much electricity as it would if occupied full-time.

design is to ensure the utility recovers sunk costs while also sending ratepayers a price signal that encourages reduction of ongoing and future costs.

In theory, a cost shift occurs whenever ratemaking deviates from pure cost causation, as this results in rates that are not directly tied to the marginal cost of serving customers. Rates designed solely on the principle of economic efficiency would theoretically allocate to each customer or group of customers the precise costs of serving them. This is not how electric rates are designed in practice; instead, ratemaking is generally based on the characteristics of the *average* customer within a class, assuming a homogeneity of customers within a class which generally does not reflect reality.

Depending on their technical characteristics and the load profile of customers adopting them, DER technologies can shift load to different hours or increase or decrease overall load level. Under a rate structure in which the majority of fixed costs are recovered by volumetric rates in the aggregate, if a DER technology reduces load level, it may shift costs onto other customers within their class, unless countervailing factors such as load growth and the value of grid services supplied by DER customers offset the reduced volumetric charges. As suggested above, policymakers must weigh whether and to what degree this potential cost shifting merits different rate treatment of DER customers, and if so, how and on what policy and evidentiary basis to develop a new rate structure.

Cost shifting in electric rates is not inherently a negative outcome. Regulators across the country, in the balancing of various factors including public policy and customer equity goals, have deemed acceptable some level of cross-subsidization between or within groups of customers. The relevant questions therefore become: what is a fair, efficient, and effective method to pursue cost recovery? Is it consistent with legislative requirements for ratemaking? Are there other, perhaps more direct, mechanisms to achieve it?

These questions can be asked of policy goals and any related cost shifting resulting from Act 236. To achieve the desired level of DER penetration, can cost shifts resulting from the state's DER policies be reduced or eliminated by taking a different approach? Are different approaches needed or preferred? The answers to these questions will depend upon the policy goals and the magnitude of any cost shift, which is dependent on a number of factors, including how DER generation is valued and accounted for. This is discussed in greater detail in the following section, *Customer-Scale Installations and the Value of DERs*.

2.3 National Trends in Rate Design

As DER adoption increases across the country, many jurisdictions are facing similar issues to those South Carolina initially aimed to address through Act 236 in 2014. Rapid development of DERs has driven the need to revisit policies and legislation several years earlier than anticipated. Utility commissions across the country are considering how best to manage this transformation. Some commissions have initiated proceedings to consider new DER rate designs and compensation mechanisms. In recognition of this trend, the National Association of Regulatory Utility Commissioners (NARUC) issued a *DER Rate Design and Compensation Manual* in 2016.[19]

With the increasing volume of DERs on utility electric systems, the historic grid paradigm characterized by centralized power plants is evolving as a growing number of customers are becoming "prosumers:" both producers *and* consumers of electricity. While this is an exciting time of technological development, these trends also expose components of traditional rate design which will require revision to accommodate the increasingly dynamic relationship between customers and utilities.

One of the most prevalent critiques of historic rate structures is their distortion of the true marginal costs of electricity. In a system where all electricity is provided by the utility, the effect of this limitation is to distort the efficient amount of energy consumed by customers, i.e., consuming more/less electricity when it is more/less expensive on a marginal basis. However, in an electric system with many prosumers, this pricing distortion additionally affects the levels of DERs that are adopted. To promote the economically efficient level of these resources, the price signals received by customers must reflect the true value of the electricity (and any other grid services) that DERs provide. While this is not an easy issue to address, current trends in customer adoption of rooftop solar, electric vehicles, energy storage, and other distributed resources suggest that it will only become more important and increasingly complex in the coming years. As discussed above, this complexity must also be balanced with other ratemaking principles, including effectiveness, equity, customer acceptance, implementation, and stability.

As DER penetration increases, utility commissions across the country are considering how best to manage this transformation. A recent trend, although not universal across the country, is a general movement away from traditional retail-rate NEM and toward different approximations of the true value of DERs. Many utilities have requested increases to fixed customer charges, arguing for the potential of under-recovery of costs from DER customers; most state public service commissions have generally reduced and often denied these requests.

South Carolina, through Act 236, developed a rate structure that is not widespread. Utilities calculate the revenue lost to solar customers and are allowed to charge a capped rate rider to collect this lost revenue. This per-customer rate rider is capped to a maximum annual charge applied monthly, and uncollected revenues plus any applicable carrying costs are collected in future years. In most other jurisdictions, utilities do not have a direct rate rider to recoup such lost revenue and will recover these costs through a different mechanism, such as increasing overall rates in the next applicable rate case. Public service commissions may or may not allow this, on the theory that a wide variety of technological changes can occur in the broader marketplace, such as solar, electric vehicles, new types of electronics, and more efficient lighting. These developments have both positive and negative effects on utility revenue, and some regulators maintain that the utility must reasonably plan for these changes.

[19] https://pubs.naruc.org/pub/19FDF48B-AA57-5160-DBA1-BE2E9C2F7EA0

2.4 Current Rates in South Carolina

South Carolina's electric rates follow traditional ratemaking practices and are therefore subject to the limitations described above relative to increasing DER penetration.[20]

Residential and small commercial customers of IOUs face a fairly straightforward, "two-part" rate structure, where energy is charged at either a flat price or with minor seasonal and/or tiered adjustments. A portion of the utilities' fixed costs are recovered through the monthly basic facilities charge and (by design) the remaining utility fixed costs are embedded in the volumetric energy rate that customers pay. As discussed above, a public policy interest in implementing relatively simple volumetric pricing is to encourage energy efficiency and give consumers more understanding of and control over their energy usage and bills.

The volumetric portion of residential rates also recovers costs that are variable to the utility and that are "passed through" to customers in an exact amount, without the rate of return associated with fixed cost investments by the utility. These variable costs include fuel cost, variable O&M, and the cost of power purchase agreements. The general price signal sent to customers through volumetric rates is one method of controlling these costs. Also, the fixed cost of the non-utility-owned solar installations are contained within power purchase agreements that are variable to the utility. To this degree, it can be argued the volumetric rate structure enables customers to support competition in the provision of fixed infrastructure.

While there is more variation in the rates charged to larger commercial and industrial (C&I) customers, most are structured as a "three-part" rate, adding more complexity but also more accuracy in the allocation of costs. In these rates, bills are determined not only by a basic facilities charge, the volume of energy consumed within a month, and a customer's power demand at a given time, which approximates the cost required to build and maintain the infrastructure necessary to serve them.

2.5 Rate Design for Distributed Energy Resources

As South Carolina considers how best to design an electricity system that accommodates the desired amount of DERs, updating electric rates to better reflect underlying costs and resource values is one potential tool to aid in this transition. Ultimately, there are important principles to consider in this discussion. One is the value of creating a rate structure that attributes fair costs and benefits to different resources based on the value those resources provide to the grid, the utility, ratepayers, and society at large. Another principle is that of gradualism. An "economically ideal" rate may be based on real-time pricing of electricity and granular measurement of the system costs imposed by each customer, but implementing such a rate would require significant improvements to metering, cost allocation, billing, and customer education and awareness.

[20] This discussion of rates focuses solely on the electric rates of DEC, DEP and SCE&G.

A variety of intermediate options could move the state further along the path toward efficient rate design and accurate cost allocation. This could also help "future proof" rate design in the expectation of increased DER adoption of solar, electric vehicles, and energy storage. Regardless of the path chosen, any rate design change will require customer education as well as analysis of distributional bill impacts to increase acceptance and smooth the transition. The following are some options that have been discussed regarding rate design choices in the context of DER compensation and better utility cost recovery. There are many other approaches and variations that have been discussed, both nationally and in South Carolina.[21]

2.5.1 TIME-OF-USE RATES

Time-of-use (TOU) rates have been offered since the 1980s and are an increasingly popular structure. TOU rates are already offered by South Carolina's IOUs as an optional alternative to the default rate for both residential and C&I customers and offered by Mid-Carolina Electric Cooperative for its residential customers. This design differentiates between peak and off-peak energy rates (and seasons), communicating a simple price signal to customers to better approximate the cost of providing electricity throughout the day and over the course of the year. By offering differentiated rates, the utility can provide price signals that better align with system demand and cost causation and thereby reduce subsidization concerns. To better reflect the cost of serving different customers, TOU rates can also be paired with other changes, such as introducing demand charges, changing the level of fixed charges, and providing compensation for grid services provided by customers.

TOU rates have been widely accepted across the country, and several jurisdictions are changing their default electricity rate to a TOU structure. Depending on the exact design of TOU rates, consumer advocates, solar industry representatives, and environmental organizations may reasonably question the fairness and predictability for customers of some proposed TOU rate structures. Various forms of bill protection and trial periods can be employed to mitigate adverse changes and ease the transition to the new rate structure.

In some cases, TOU charges have been proposed for DER customers, but not for non-DER customers. While this mandatory TOU approach for DER customers may reduce subsidization, it will not eliminate the concern. This approach was not necessarily embraced by the Act 236: 2.0 stakeholder group, either from solar-focused entities or utilities, although SCE&G has stated that they do not oppose TOU rates.

2.5.2 DEMAND CHARGES

Another approach to better matching rate design to cost causation is to include both an energy and demand charge for all customers, rather than only for larger C&I customers. Demand charges allow utilities to distinguish between *customer-specific* fixed costs for items such as meters and billing (recovered through a monthly fixed charge such as SCE&G's basic facilities charge) and the fixed *system*

[21] https://www.raponline.org/knowledge-center/smart-rate-design-for-a-smart-future/; https://pubs.naruc.org/pub/19FDF48B-AA57-5160-DBA1-BE2E9C2F7EA0; https://rmi.org/wp-content/uploads/2017/04/A-Review-of-Alternative-Rate-Designs-2016.pdf; http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7BA0BF2F42-82A1-4ED0-AE6D-D7E38F8D655D%7D

or demand-related cost, to which customers contribute based on the intensity of their grid utilization (i.e., how much power they demand at a given time).

Demand may be measured based on the average of several peak demand levels throughout the course of a billing period or on the rolling average of daily peak demand, to name a few common approaches. Perhaps the most common approach among large C&I customers is to measure demand on a 15-minute or hourly basis, frequently with a demand "ratchet" that can require customers to pay at least a minimum charge for the highest usage during the whole year. Since small customers are served as a group on a single residential feeder, it is unclear whether this approach would properly account for the aggregate demand impacts of a group of small customers.

As with discussions around TOU rates, consumer advocates and others question the fairness of applying demand charges to residential and small commercial customers and the ability of these customers to track and understand the impact of fluctuations in usage on their bills. These concerns are valid and could potentially be mitigated using the same bill protection mechanisms discussed relative to TOU rates. Customer outreach and education are also crucial to ensuring increased acceptance of rate design changes. Alternatively, demand charges could only be employed for smaller customers, rather than the entire customer base. Fifty utilities in 21 states currently offer residential electric rates that include demand charges, predominantly for DER customers only.[22]

Finally, it is important to note that demand charges and TOU rates are not mutually exclusive and can be combined to create a rate structure that allocates costs based on energy usage and demand in a more accurate fashion than either change can achieve in isolation. DEC and SCE&G offer such combined structures as an optional rate for all residential customers, as do some of the electric cooperatives in South Carolina. In addition to the TOU rate mentioned above, Mid-Carolina Electric Cooperative made demand-based rates the standard rate design for residential and small commercial customers. Some stakeholders have pointed it out as a model for future rate design for all utilities. It includes a fixed charge of approximately 90 cents a day, or approximately $27 per month.

2.5.3 SEPARATE DER CUSTOMER CLASS

Another option often discussed is to separate DER customers into their own, distinct rate class. This approach recognizes that DER customer characteristics (i.e., energy usage and demand patterns) are different from those of non-DER customers currently included in the same class. The Kansas Corporation Commission has ordered that DER customers be considered a separate class, and in other states (e.g. Montana) legislation has allowed for creation of separate rate classes.[23] To create a separate rate class, data specific to DER customers must be considered within the context of a general rate case to determine whether a separate rate class is merited without undue discrimination. Collection and characterization of illustrative relevant data was suggested by DER advocates in this collaborative series of meetings but was deemed outside the scope of this report. The IOUs have not necessarily advocated for a separate rate

[22] "Rate Design for DE Customers in New York." Ahmad Faruqui and Sanem Sergici. The Brattle Group. March 2018.
[23] "In new trend, utilities propose separate rate classes for solar customers without rate increase." Herman K Trabish. Utility Dive. November 2, 2017. https://www.utilitydive.com/news/in-new-trend-utilities-propose-separate-rate-classes-for-solar-customers-w/508393/

class, either. Rather, DER advocates and some South Carolina utilities favor development of rates that can be fairly applied across all residential customers, rather than singling out DER customers as their own rate class.

2.5.4 ADDITIONAL DER RATE DESIGN OPTIONS

Beyond the several options discussed above, there are a variety of other approaches to designing rates for DER customers. These include adjustments to fixed charges (such as South Carolina's basic facilities charge), standby charges meant to recover the costs of maintaining additional generation capacity for the times when a DER customer is not generating electricity, and various forms of demand charges (e.g., with demand measured more or less frequently, or over different time intervals), among others. In addition to rate design components, there are also different approaches to DER compensation, including but not limited to net metering. For an in-depth discussion of DER rate design options, see the NARUC 2016 *Manual on Distributed Energy Resources Rate Design and Compensation*.[24]

[24] https://pubs.naruc.org/pub/19FDF48B-AA57-5160-DBA1-BE2E9C2F7EA0

3 Customer-Scale Installations and the Value of DERs[25]

Key Takeaways

- The value assigned to DERs has a **fundamental impact** on the **magnitude** of any **cost shift** from net metering of these resources.
- Different jurisdictions have taken a wide variety of approaches to DER valuation, including assigning amounts to components currently considered to have a zero-value in South Carolina.

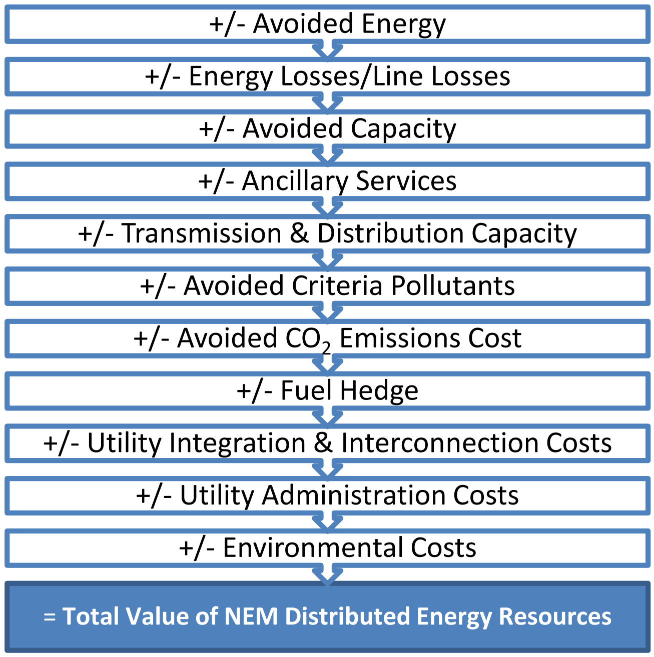
Areas of Contention

- **Avoided cost values** have been **contested each year** since the passage of Act 236.
- Stakeholders disagree as to **whether the Act 236 2.0 process** is the **correct forum for discussing avoided costs**, given the PSC has already been given authority over their calculation methodology by state lawmakers.
- Some stakeholders feel that there are reasonable approaches to obtaining certain values within the NEM methodology, while others disagree and assert that it is not cost-effective to do so at this time.

In March 2015, the Commission approved the Settlement Agreement[26] reached by the stakeholder group involved in the creation of Act 236 and adopted the current methodology used to compute the value of generation from net-metered DERs.[27] Figure 4 depicts this methodology.

[25] Throughout this section, the terms *Value of DERs* and *Value of Solar* are used interchangeably
[26] The Settlement Agreement is discussed in greater detail in Section 4: Cost Shift Report.
[27] Order No. 2015-194.

Figure 4. Net Energy Metering Methodology[28]



While this methodology was agreed upon as part of the Settlement Agreement, the individual components of the calculation are established for each utility by the Commission in annual proceedings. Parties frequently disagree about such calculations in evidentiary hearings before the Commission, presenting arguments as to different values they believe to be appropriate for the individual components. Ultimately, the decision reached by the Commission establishes the monetary value of each component, and thereby the overall valuation of DERs.

The Commission allows for some of the components to be used as placeholders "where there is currently a lack of capability to accurately quantify a particular category and/or a lack of definable cost or benefit to the Utility system."[29] Of the eleven components included in this calculation, seven were assigned a zero-value by the utilities in their most recent annual fuel filings.[30] The components which were assigned a zero-value include: Ancillary Services, Transmission & Distribution Capacity, Avoided CO_2 Emissions, Fuel Hedge, Utility Integration & Interconnection, Utility Administrative, and Environmental. The utilities' position is that some of these zero-values are placeholders while others are appropriately valued at zero. Duke Energy also notes that its avoided Fuel Hedge costs are embedded in the avoided energy costs.

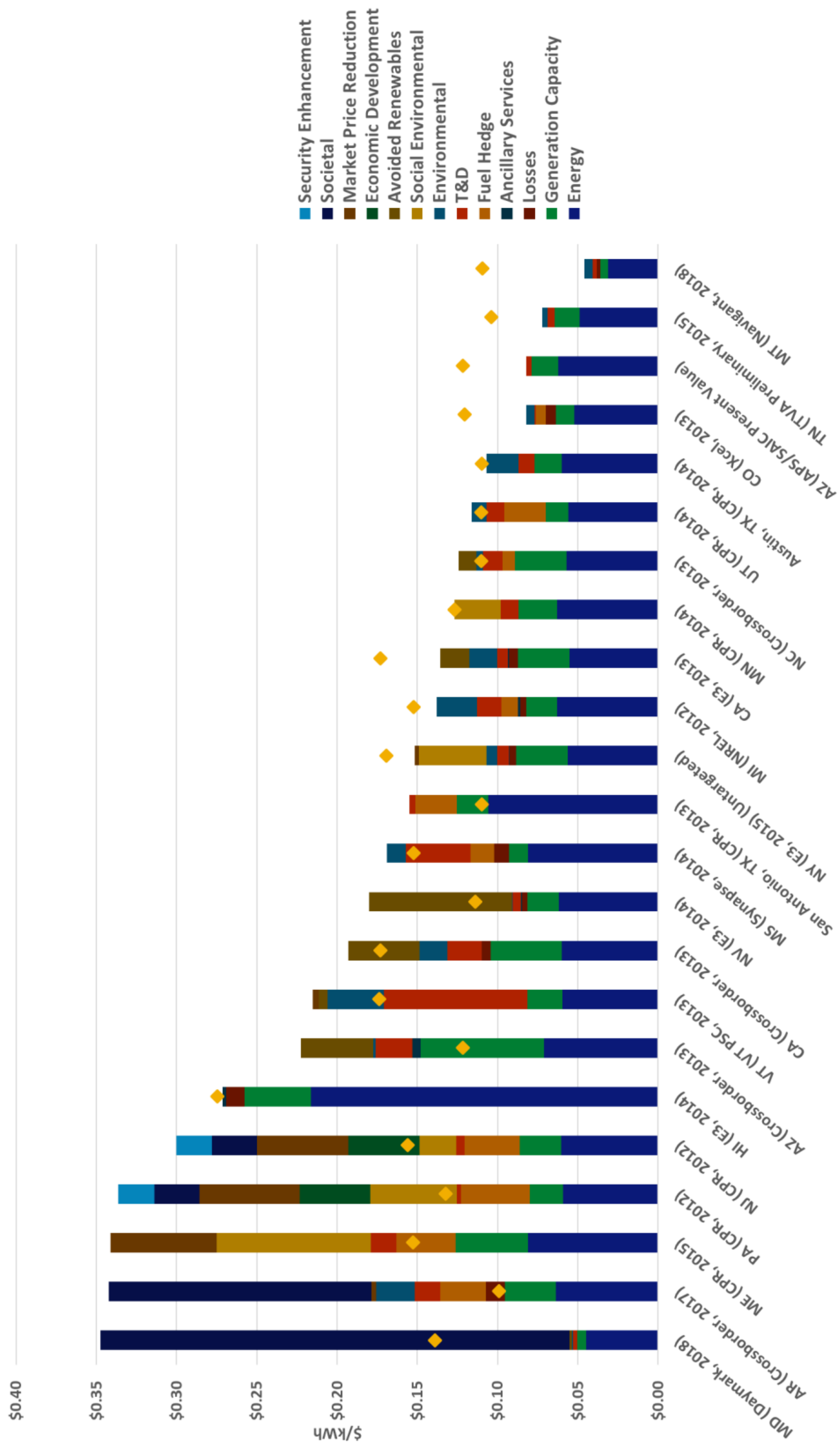
Order No. 2015-194 requires component values to be updated if and when "capabilities to reasonably quantify those values and quantifiable costs or benefits to the Utility system in such categories become

[28] For additional information on the individual components, please see Figure 3 and 4 (pages 9-10 and 12) of the 2015 *South Carolina Act 236 Cost Shift and Cost of Service Analysis* prepared by E3 on behalf of the ORS: https://www.regulatorystaff.sc.gov/electric/industryinfo/Documents/Act%20236%20Cost%20Shifting%20Report.pdf.
[29] Ibid.
[30] One stakeholder notes that the Public Service Commission has ruled in favor of utility parties each year, and on every component.

available." Various parties hold that some of the component values currently given a value of zero in South Carolina can, in fact, be reasonably quantified, and therefore must be included in the NEM DER calculation. For example, some stakeholders note that other jurisdictions derive values for avoided transmission and distribution capacity, and for avoided CO_2 costs. While this report will not discuss the feasibility of calculating these different values in detail, the *Value of Solar* section of the Appendix (section 9.1) contains a comparison of two different approaches taken to populating the values currently assigned a zero-value in South Carolina. There is broad variation across jurisdictions with regard to which components are calculated in Value of Solar studies and the actual value of these components.

Figure 5 provides a sense of this variation and highlights that some states do assign a value to the placeholder zero-values in South Carolina. Note that this figure only includes benefits assessed from DERs; see section 9.1.1 of the Appendix for an analogous figure depicting costs assessed (few studies assess both benefits and costs of DERs).

Figure 5. Avoided Cost Benefits Across Different Value of Solar Studies



Beyond the components currently assigned a zero-value, there has also been disagreement over the proper derivation of the four non-zero-values used in the NEM methodology. Perhaps most notably, SCE&G received approval in its 2018 fuel cost proceeding to include a zero-value for avoided capacity.[31] Historically, capacity has been the second-largest avoided cost component in the value of solar in many jurisdictions, after avoided energy. Prior to 2018, SCE&G had used a non-zero-value for avoided capacity. This value in 2016 represented approximately 15% of the total assessed value of net-metered DERs in SCE&G territory; in 2017, it represented approximately 5% of total value.[32]

The newly calculated avoided generation capacity value of zero received significant negative comments from various parties to the proceeding – both relative to the effect on DERs and to utility-scale developers reliant upon avoided cost-based rates to finance their projects. While this is likely to be brought up again, SCE&G has indicated throughout the Act 236: Version 2.0 process that it believes in the validity of its approach to calculating avoided capacity costs and notes that the zero-value has been approved by the Commission.

3.1 Effect on DER Valuation

The effect of changing avoided costs or other values in the NEM methodology depends both upon the specific amounts assigned and on the relative value of different components. Some placeholder values may represent directly monetized avoided costs or benefits (e.g., ancillary services) that may currently be small and/or difficult to quantify, while others are for actual costs incurred by the utility (e.g., integration), and therefore the effect on DER valuation depends upon the net benefits (e.g., benefits minus costs).

With NEM in its current form and under existing parameters, however, the assessment of DER value remains a question of presumed program costs and calculations of potential cost shifting, rather than a direct pricing of DER value to customers. In other words, changes to this valuation therefore will not affect customer-scale adoption in the short-term. Instead, these changes will impact the amount of unrecovered utility revenue that is being recovered from all ratepayers as a DER program cost, also known as a "cost shift," discussed in the next section. In contrast, the calculation of avoided costs has a direct effect on larger, utility-scale developers who are compensated based on the values assigned to avoided costs; this issue will be discussed further in the *PURPA, Interconnection and Utility-scale Resources* section.

[31] Order No. 2018-322, Docket No. 2018-2-E.
[32] "Status Report on Distributed Energy resource and Net Energy Metering Implementation." South Carolina Office of Regulatory Staff. July 2017.

4 Cost Shift Report

Key Takeaways

- This net metering cost shift estimate is **higher than previous assessments**, driven predominantly by **increases in expected customer-scale solar installations** and **decreases in avoided cost values**.
- No retail rate adjustments have been made in the cost shift analysis as a result of the outcome of the VC Summer proceeding, although E3 has separately estimated the potential impact this could have on retail electric rates.

Areas of Contention

- Stakeholders disagree **whether NEM** should be **considered a cost shift**, given this is **predicated on utilities** being **permitted to recover** the **cost of lost retail revenues**.
- In some cases, stakeholders disagree about the calculated avoided cost values, which are a key input into the cost shift calculation. Some stakeholders disagree with the methodology used to calculate the cost shift.

4.1 South Carolina NEM Background

While Act 236 was passed in June 2014, the specific treatment of the current NEM program in South Carolina originates from a generic proceeding initiated by the Public Service Commission and negotiations between the parties, culminating in the filing of a Settlement Agreement with the Commission, which was approved in March 2015.[33] While several parties did not join the Settlement Agreement as signatories, they indicated that they did not oppose its adoption by the Commission.[34] Many of the same stakeholders who have participated in the 2018 meetings, which culminated in the creation of this report, were parties to the original collaborative process.

It is worth noting that despite reaching the Settlement Agreement in the 2015 proceeding, many participants had divergent views of how the Commission should value the costs and benefits of DERs in

[33] Order 2015-194.
[34] Ibid.

the absence of the Settlement Agreement. This was acknowledged in the Settlement Agreement itself, and reflected in testimony filed in the same proceeding, for the Commission's consideration in the event the agreement was not approved.[35]

The cost shift analysis detailed in this section focuses specifically on NEM, given that this is the current compensation policy for customer-scale solar in South Carolina.[36] NEM is a widely used compensation mechanism for DER generation. NEM typically credits DER customers for their generation on a 1:1 retail basis, thereby valuing the electricity generated by DERs (whether consumed on-site by that customer or exported to the electric grid) equivalently to electricity which otherwise would have been provided by the utility. Alternative policies also exist, such as compensation for solar resources at the "Value of Solar" established by public service commissions (see Section 3) or at the utility's avoided costs of providing that energy, among other approaches.

For the purposes of this report, the NEM cost shift is defined as the difference between what a DER is paid for the services it provides and the value the Commission attributes to those services. In this report the NEM cost shift is therefore calculated as the difference between the compensation received for generation from DERs via 1:1 bill crediting at the full volumetric retail rate and the established value of DER to the utility's electric system. This calculation reflects the DER NEM incentive as defined by the 2015 Settlement Agreement, which the utilities collect as a DER program expense through annual fuel proceedings.[37] In this way, the DER program cost is presented to the Commission for review on an annual basis, along with other costs of serving customers such as procuring fuel for electricity generation.

South Carolina is only one of two states (along with Massachusetts) allowing for recovery of uncollected costs due to full retail NEM in this fashion. Several stakeholders have also noted that including construction costs for nuclear power plants in electric rates has increased the NEM cost shift by creating a larger discrepancy between calculated DER values and retail rates.

4.2 Methodology

To estimate the NEM cost shift in South Carolina, E3 used historical and forecast DER installation data, specifically for solar; approved avoided cost rates and forecast trends in these rates; and reported utility expenditures on NEM, where available. This approach builds on a 2015 analysis of the estimated NEM cost shift from DERs in South Carolina which E3 conducted on behalf of ORS,[38]well as updates to that analysis conducted to support ORS in its reporting on DER implementation, as required by Act 236.[39] The updated estimate of the DER NEM cost shift detailed in this section is larger than the 2015 estimate, driven

[35] Docket 2014-246-E.
[36] Act 236 established NEM as the compensation policy for customer-scale in DEC, DEP and SCE&G "until the generating capacity of net energy metering systems equals two percent of the previous five-year average of the electrical utility's South Carolina retail peak demand." This limit on NEM is often referred to as a "NEM cap."
[37] Order 2015-194.
[38] https://www.regulatorystaff.sc.gov/electric/industryinfo/Documents/Act%20236%20Cost%20Shifting%20Report.pdf
[39] S.C. Code Ann. § 58-39-140(E).

predominantly by increases in expected customer-scale solar installations and decreases in avoided cost values.

In addition to estimating the NEM cost shift, this section also documents total incremental DER program costs, as reported (2015-2018) and forecast (2019-2021) by the utilities. This includes both the costs of the NEM program and all other DER program costs recovered from customers through the monthly DER program charge, such as community solar, utility-scale solar, and incentive programs.

Forecasting customer DER installation trends and future utility avoided costs is challenging, given the large degree of uncertainty involved.[40] As such, the figures in this section should be considered simply as estimates of potential future outcomes; they should not be taken as a precise depiction of what DER costs in South Carolina will be in the coming years. This is especially true given the dependency of these costs on policy and regulatory decisions, such as what compensation policy will be used for customer-scale DER in South Carolina. Depending on policy and regulatory actions in the coming years, both the level of DER installation and the associated program costs could look significantly different.

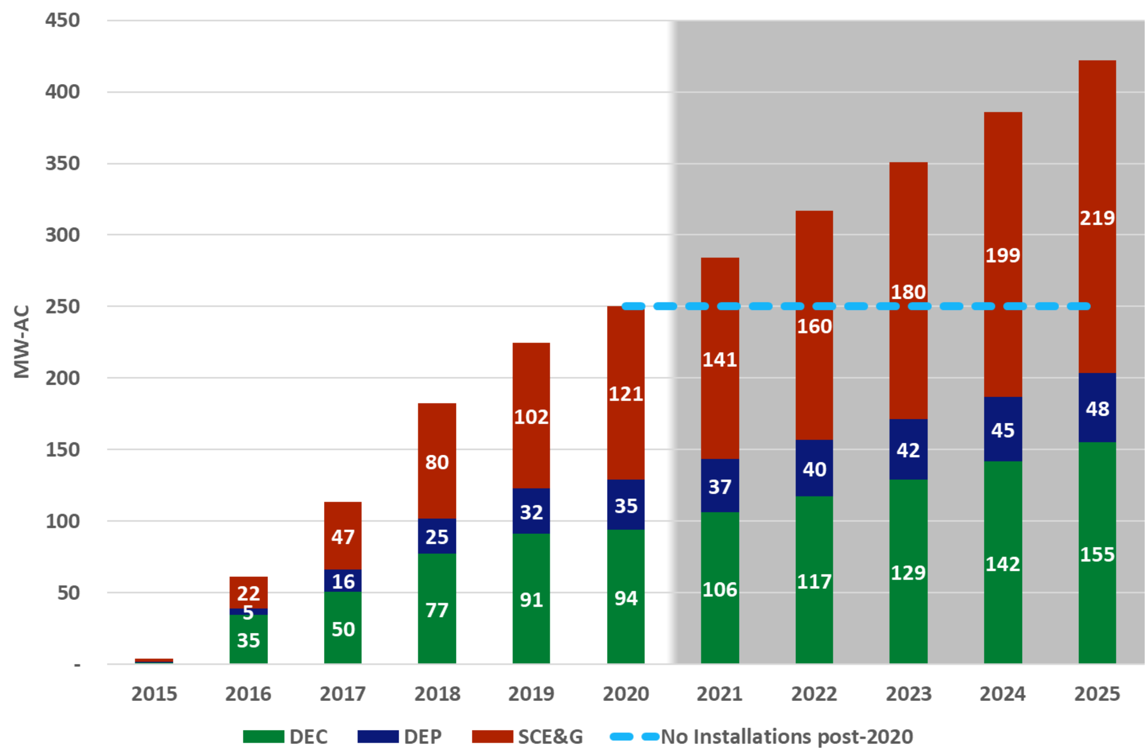
For further details of the cost shift methodology and data sources, please see Appendix 9.7.

4.3 Installation Forecast

Relative to expectations at the time Act 236 was passed, both actual installations (since 2015) and forecasts of future development have increased significantly. Whereas the 2015 cost shift analysis conducted by E3 assumed a cumulative installed customer-scale capacity in 2020 of 105 MW-AC[41], updated forecasts provided by the utilities anticipate approximately 250 MW of customer-scale solar to be installed by 2020, a 137% increase from the original forecast. Figure 6 depicts the current forecast from each utility.[42]

[40] For example, the scheduled termination of the federal Investment Tax Credit will have some cooling effect on customer-scale solar adoption, but the costs for this resource will likely continue to decline. The relative effect of these different influences is difficult to gauge.
[41] Based on the goals set by Act 236.
[42] 2015 installations: DEC: 1.05 MW-AC, DEP: 0.76 MW-AC, SCE&G: 1.94 MW-AC; DEC and DEP values estimated.

Figure 6. Cumulative Customer-Scale Solar Capacity by Utility



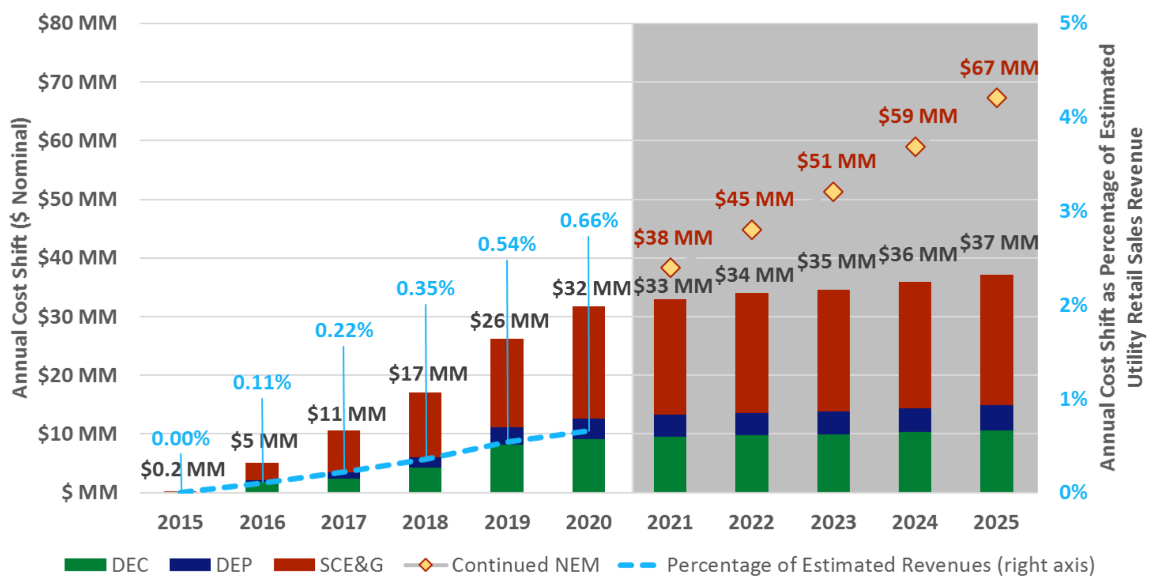
Given the uncertainty around compensation policy for customer-scale systems installed beyond 2020, the forecast for 2019 and 2020 should be considered more confident than for subsequent years, as actual installations will depend inherently on how they are valued and compensated. This uncertainty beyond 2020 is denoted by the grey background for the years 2021-2025. The dashed blue line carries forward the total anticipated customer-scale capacity in 2020 (250 MW) and indicates a scenario in which no additional installations take place past that year. This serves as a baseline against which to view the utilities' installations forecasts, which assume continued compensation at rates above avoided costs.

4.4 Estimated NEM Cost Shift

The estimated NEM cost shift in 2015-2018 is based on historic installation data and approved avoided cost rates. Using these values, we estimate that DERs in South Carolina have provided approximately $25 million in total value to the electric utilities since 2015. Over the same period, DERs have reduced utility electricity sales by approximately $58 million. This difference equates to a total nominal cost shift of roughly $33 million since the beginning of NEM as a result of Act 236.

Estimates of the NEM cost shift for the years 2019-2025 rely instead on forecasted installations and utility expectations of avoided cost rates. Figure 7 provides a summary of the estimated NEM cost shift in each year. In addition to the nominal values in dollars, we provide an estimate of the cost shift as a percentage of utility electricity retail sales revenues.

Figure 7. Estimated Annual NEM Cost Shift by Utility[43]



In this figure, the uncertainty beyond 2020 is once again denoted by the grey background for the years 2021-2025. The column chart indicates the estimated annual NEM cost shift if no additional customer-scale systems are installed beyond 2020. This forecast is intended to convey what the estimated NEM cost shift would be if the current NEM policy is not maintained as the compensation mechanism for new customers, while customers participating in NEM continue through the Settlement Agreement-approved grandfathering period of December 2025. In this scenario, the net present value of the estimated NEM cost shift for 2019-2025 is approximately $173 million.[44]

In contrast, the yellow points indicate the estimated cost shift in each year if installations reach the levels forecast by the utilities.[45] In this scenario, the net present value of the estimated cost shift for 2019-2025 is approximately $230 million.

[43] Estimated electric revenues are sourced from data from S&P Global and FERC Form 1. Estimated revenues are calculated for 2015-2017 and held constant for 2017-2020.
[44] For all net present value calculations in this section, E3 used a nominal discount rate of 7.6%.
[45] The Duke utilities note that the higher level of forecast installations in Figure 6 (and driving the larger NEM cost shift estimates in Figure 7) are based on a "middle ground" compensation mechanism, valued between avoided cost rates and full retail 1:1 bill crediting. The SCE&G installation forecast is based on continued, full retail 1:1 bill crediting as under current NEM policy. These differences further highlight the uncertainty surrounding anticipated installations and compensation mechanism.

Estimates of the NEM cost shift under these two scenarios serve to "bookend" the range of potential NEM cost shifts, given the uncertainty as to which compensation mechanism remains in place, and the subsequent effect this would have on customer-scale installations.

Given recent discussions of a settlement agreement between SCE&G parent company SCANA and its ratepayers regarding cost allocation for abandoned nuclear reactor construction, E3 estimated what effect this would have on the NEM cost shift. Based on our modeling, a 10% reduction in SCE&G's retail rates would equate to an average 13% decrease in the annual NEM cost shift for SCE&G.

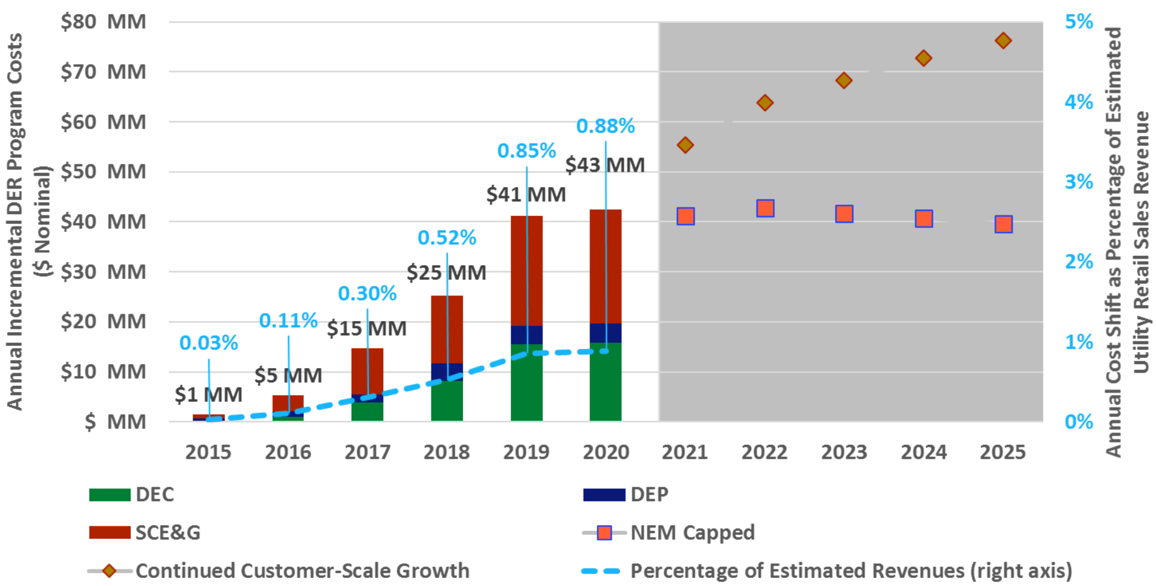
4.5 Total Incremental DER Program Cost

Beyond the cost shift from NEM of DERs, there are additional DER program costs incurred by the utilities and passed along to ratepayers. These include, for example, rebate programs and performance-based incentives, community-scale solar, utility-scale solar, the costs of meters required for NEM, general and administrative expenses, and the carrying costs for deferred collections from previous years.[46] Deferred collections are created due to annual cost recovery caps established in Act 236.[47] Carrying costs are then added to these deferred collections, and the total is reallocated across all customer classes for recovery in subsequent years. As deferred collections recur over the years, additional carrying costs will continue to be incurred and will increase in a climate of inclining interest rates. It is currently estimated that DER incremental program costs will continue to be paid monthly by ratepayers until approximately the 2040 timeframe or beyond. To date, incremental DER program costs across the three IOUs have totaled approximately $47 million.

Figure 8 depicts the total program cost for the full suite of DER programs, including NEM driven by Act 236, as well as two different estimates of potential future DER program costs. In addition to the nominal values in dollars, we provide an estimate of the cost as a percentage of utility electricity retail sales revenues.

[46] One example of a relatively large deferred collection is the rebate program offered by the Duke utilities. While customers receive the incentive funds upfront, the cost is amortized by the utilities and collected over a number of years, inclusive of carrying costs.
[47] The cost recovery caps for residential, commercial and industrial customers are $12/year, $120/year and $1,200/year, respectively.

Figure 8. Estimated Annual Total Incremental DER Program Cost by Utility (inclusive of NEM)[43]



The columns in this figure report total incremental DER program costs for each utility for the years 2015-2018, as well as an estimate of the costs for the years 2019 and 2020. In addition, two different estimates are shown for the years 2021-2025. The pink squares indicate estimated total incremental DER program costs assuming that NEM does not continue beyond the limits approved in the 2015 Settlement Agreement.[48] The orange points estimate total incremental DER program costs for a scenario in which customer-scale DERs continue to be compensated at a rate above avoided costs.[49] As with the previous figures, the uncertainty beyond 2020 is denoted by the grey background for the years 2021-2025.

As with the installation forecast and estimated NEM cost shift, forecast values (especially for 2021-2025) should be considered merely as estimates subject to significant uncertainty. The divergent estimates of total annual incremental DER program costs are intended to highlight that these costs will depend inherently on the range of potential NEM cost shift values highlighted earlier in this section and are therefore subject to the same forecasting limitations.

[48] This estimate includes an adjustment for the recently-approved extension of NEM through March 15, 2019, in DEC territory.
[49] The Duke utilities note that in a scenario with full retail NEM continued through 2025, the total program cost could potentially be higher than the upper bound estimate in this figure, as their installation forecasts provided for the years 2021-2025 assume a compensation mechanism between avoided cost rates and full retail NEM (and with full retail NEM, installations would likely be higher). However, given this upper bound estimate is based on historic total DER program costs, which include the Duke utilities' rebate programs, it likely overstates total costs for 2019-2025 (which would not include new rebate programs). On net, Duke finds this figure to be an appropriate estimate of the range of potential DER program costs in the coming years.

5 Low-to-Moderate Income Customers

Key Takeaways

- Energy bills represent a **larger portion of low-to-moderate income (LMI) customers' incomes** than they do for other customers.
- **Current LMI energy assistance programs** in South Carolina **serve a relatively small portion of the LMI population** and are largely funded by federal grants.
- Other states have taken **various approaches** to providing energy bill assistance to LMI customers, any of which could be applied in South Carolina, if desired.

Areas of Contention

- While all stakeholders support LMI customer assistance, there is disagreement over the appropriate approach and whether this stakeholder process is the best opportunity for action, given that LMI equity issues extend beyond the focus of this group.

Several stakeholders in the Act 236: Version 2.0 meetings expressed a desire to use this collaborative process as an opportunity to reconsider and improve upon how South Carolina meets the energy needs of its low-to-moderate income (LMI) residents. In this section we briefly describe the energy challenges faced by LMI customers. An overview of the existing energy programs available to the LMI population in South Carolina, a listing of other potential approaches for offering affordable energy services to these customers, and a proposal developed by a subgroup of stakeholders to provide relief to low-income consumers can be found in the Appendix (see sections 9.2-9.4).

5.1 Energy Challenges Faced by LMI Residents

Energy expenses typically represent a higher proportion of household budgets for LMI families and individuals than they do for the general population. Exacerbating this issue, energy-saving measures such as efficiency retrofits and energy efficient appliances are often inaccessible to LMI residents given the upfront cost premium they require and/or lack of customer awareness. Finally, as many LMI customers are renters rather than homeowners, there is a further disincentive to invest in energy-saving measures or home upgrades given the length of tenancy in each residence is often uncertain and the value remains with the owner, not the tenant.

These issues are of particular concern in South Carolina, as the state's poverty rate is greater than the national average (estimated at 15.3% and 14%, respectively),[50,51] and LMI customers in the region have some of the highest energy burdens (proportion of expenses allocated to energy) in the nation.[52]

An alternative estimate of LMI customers in the state comes from assessments of eligibility for the federal Supplemental Nutrition Assistance Program (SNAP), as determined by the South Carolina Department of Social Services (DSS). Through September 2018, a year-to-date monthly average of 292,048 South Carolina households, representing 626,876 individuals, received SNAP benefits.[53] While the DSS notes the population receiving these benefits has decreased in recent years (from a 2012 peak of 879,000 individuals to 620,912 in September 2018),[54] total eligible residents may constitute a significantly higher number.

5.2 Existing LMI Energy Programs in South Carolina

The main energy assistance programs for LMI customers in South Carolina are the federal Low Income Home Energy Assistance Program (LIHEAP) and the Department of Energy's Weatherization Assistance Program (WAP). LIHEAP is a block grant funded by the U.S. Department of Health and Human Services that provides funding assistance to LMI households for various energy-related upgrades. WAP provides additional funding for home weatherization to LMI customers.

In addition to the federal programs, the large IOUs in South Carolina provide, or will soon provide, various types of assistance to LMI customers, including specific allocations for LMI customers in their community solar programs. SCE&G currently subscribes 160 LMI customers in its program, while DEC and DEP will each be allocating 200 2 kW shares to LMI customers.

Please see sections 9.2-9.4 of the Appendix for further detail on these LMI programs, including an assessment of the South Carolina population served by the federal initiatives.

[50] U.S. Census Bureau, Small Area Income and Poverty Estimates Program (2016 data).
[51] While South Carolina's poverty rate is above the national average, it is on the lower end of the regional spectrum of poverty rates: North Carolina's poverty rate is 15.4%, while Georgia, Florida, and Tennessee come in at 16.1%, 14.8%, and 15.8%, respectively.
[52] "The High Cost of Energy in Rural America: Household Energy Burdens and Opportunities for Energy Efficiency." American Council for an Energy-Efficient Economy. July 2018.
[53] "SNAP Participation: September 2018." South Carolina Department of Social Services. https://dss.sc.gov/media/1866/fs_201809.pdf
[54] South Carolina Department of Social Services. https://dss.sc.gov/assistance-program and Ibid.

6 Commercial and Industrial Renewable Energy Programs

Key Takeaways

- Green Tariff programs **internalize incremental costs**, thereby avoiding the potential for cost shifting to non-participating customers.
- Various program structures allow for **customization to specific state scenarios**.

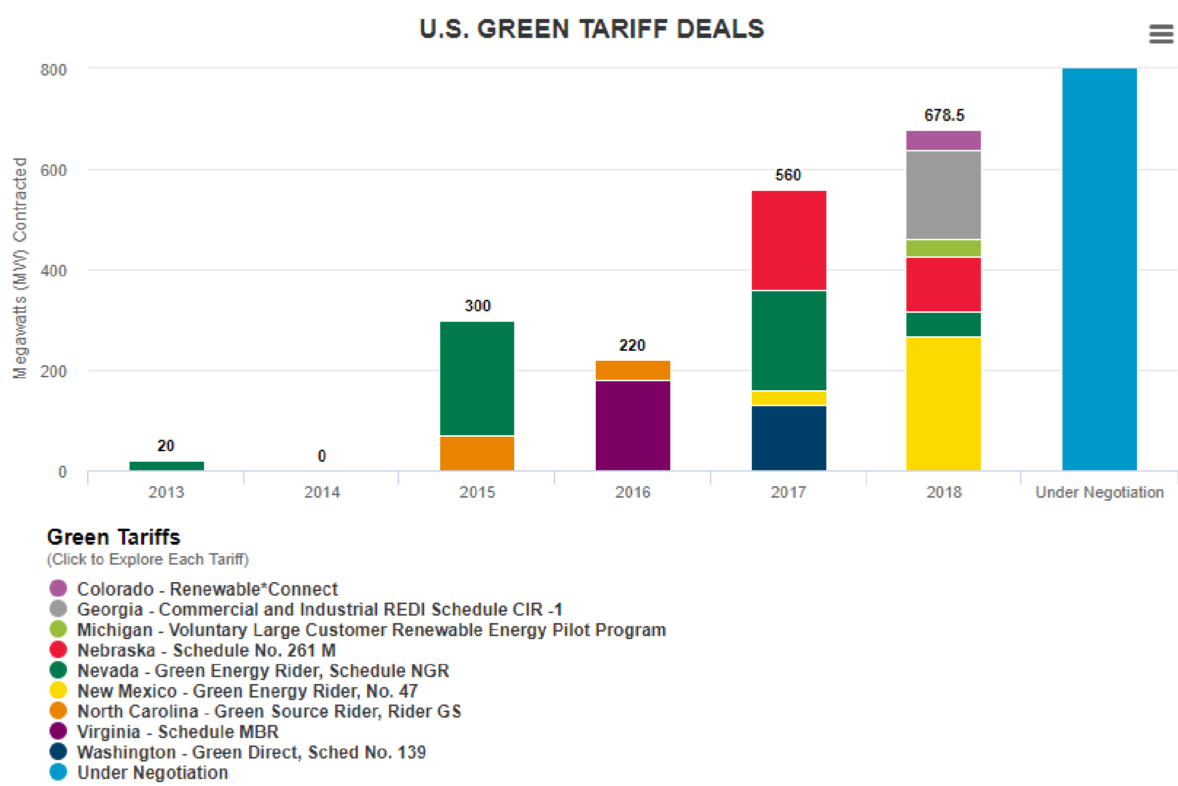
Areas of Contention

- Some stakeholders note that proposed Green Tariff programs in South Carolina will not be available to all customers given current eligibility criteria.

Larger commercial and industrial (C&I) customers – who generally pay more attention to their electricity usage – have required an expanded set of options and choices as compared to residential and small commercial programs such as NEM and community solar. These larger customers are increasingly demanding choices better suited to meeting their energy and sustainability goals, and utilities across the country are responding with a variety of programs, commonly referred to as Green Tariffs. As of February 2018, 21 Green Tariffs have been proposed or approved in 15 states.[55] Figure 9 demonstrates the growth in renewable capacity provided by these programs in recent years.[56]

[55] "Utility Green Tariffs." U.S. Environmental Protection Agency. https://www.epa.gov/greenpower/utility-green-tariffs
[56] "Grid Transformation: Green Tariff Deals." World Resources Institute. 2017. https://www.wri.org/resources/charts-graphs/grid-transformation-green-tariff-deals

Figure 9. U.S. Green Tariff Deals



Green Tariffs allow C&I customers in regulated electricity markets like South Carolina to purchase bundled renewable energy from a specific generating project and pay for it through a special utility tariff.[57] Beyond achieving specific customer renewable energy and sustainability goals, enrollment in Green Tariffs can also reduce long-term energy price risks, depending on program structure. While these programs differ in their implementation, an important commonality is that costs are internalized by the group of participating customers. The internalization of costs avoids or at least mitigates the potential for cost shifting to the utility's other ratepayers, depending on the specific Green Tariff design.

While South Carolina has yet to approve a Green Tariff, DEC and DEP jointly submitted a proposal to the PSC to create the state's first program on October 10, 2018.[58] These programs are currently before the Commission, which will ultimately weigh any comments from interested parties before rendering a decision.

[57] "Utility Green Tariffs." U.S. Environmental Protection Agency. https://www.epa.gov/greenpower/utility-green-tariffs
[58] Docket 2018-320-E.

6.1 Green Tariff Programs in Other Jurisdictions

There are four main categories of Green Tariff programs. Table 2 compares these structures and provides examples of each.[59,60] Note that the program recently proposed by Duke is of the first program type, utilizing "Sleeved" Power Purchase Agreements (PPAs).[61]

Table 2. Primary Green Tariff Structures

Program Type	Description	Examples
Sleeved PPAs	Customers purchase energy from a renewable energy (RE) developer, with the PPA "sleeved" through the utility. Utility administers transactions between parties and collects admin fees from customer to cover incremental costs.	• Duke SC: Green Source Adder (proposed) • Duke NC: Green Source Rider • NV Energy: Green Energy Rider • Rocky Mountain Power (UT): Schedule 32
Subscriptions	Similar structure to Sleeved PPA, but multiple customers served by one or more RE facility, which is owned or contracted for by the utility. Can provide greater flexibility than Sleeved PPA in terms of contract length, subscription size, and pricing transparency.	• Georgia Power: C&I Renewable Energy Development Initiative • Xcel (CO and MN): Renewable*Connect • Puget Sound Energy (WA): Green Direct
Market-Based Rates	Leverages access to organized wholesale market. Vertically-integrated utility serves as middle man, scheduling market participation for a RE facility, with whom customer has signed a PPA for energy and Renewable Energy Credits (RECs). Utility sells RE output into wholesale market, and the market price received is credited to the customer. Customer pays wholesale rate for its energy consumption, which is highly correlated with the price received for RE output.	• Dominion (VA): Schedule Market Based Rate • Omaha Public Power: Schedule No. 261M • Consumer Energy (MI): LC-REP Option B
System Resource REC Purchases	Allows customers to buy RECs and/or other environmental attributes from projects procured to meet system needs. Customer participation in this manner can enable development of new RE which benefits all utility customers.	• Dominion (VA): Schedule Renewable Facility

[59] "Here's what corporate buyers can expect from green tariffs." GreenBiz. Caitlin Marquis. August 2, 2018. https://www.greenbiz.com/article/heres-what-corporate-buyers-can-expect-green-tariffs
[60] "Implementation Guide for Utilities: Designing Renewable Energy Products to Meet Large Energy Customer Needs." World Resources Institute. Priya Barua. June 2017.
[61] Docket 2018-320-E.

Not all program structures are feasible in South Carolina, given certain dependencies on external market structures. For example, *Market-Based Rates* programs require access to an organized wholesale market, which South Carolina does not have. As the state considers the best way to implement C&I Green Tariff programs, policymakers and other stakeholders should consider how the relevant structures can be customized to provide cost-effective options for interested customers. For example, a subscription-style program could potentially prove more attractive to a broader range of C&I customers than Duke's recent filing, given the added flexibility in terms of contract length and subscription size. As the aim of these programs is to serve customers who are seeking additional options for accessing renewable energy, it will be critical to include feedback from these customers in the design of future Green Tariffs.

7 PURPA, Interconnection, and Utility-scale Resources

Key Takeaways

- South Carolina may want to consider **further review** of its **avoided cost calculations**.
- **Interconnection of utility-scale projects** could likely be **streamlined** through several key process changes.
- As North Carolina solicits large amounts of new solar, South Carolina will need to actively ensure **equity in its interconnection process**.

Areas of Contention

- Stakeholders disagree as to **whether** or not the **current avoided cost methodology** accurately reflects the **true value** of non-utility generation resources.

The key questions surrounding utility-scale project development in South Carolina center on two related topics: PURPA and Interconnection.

7.1 Public Utilities Regulatory Policies Act (PURPA) of 1978

7.1.1 WHAT IS PURPA?

As part of the National Energy Act, in 1978 Congress passed the Public Utilities Regulatory Policies Act (PURPA), which was designed, among other things, to encourage conservation of electric energy, increase efficiency in use of facilities and resources by utilities, and produce more equitable retail rates for electric consumers.[62]

[62] *National Association of Regulatory Utility Commissioners. PURPA Title II Compliance Manual. By Robert E. Burns and Kenneth Rose. N.p.: n.p., 2014.* Page 5. https://pubs.naruc.org/pub/B5B60741-CD40-7598-06EC-F63DF7BB12DC

To help PURPA accomplish its goals, a special class of generating facilities called Qualifying Facilities (QFs) was established. QFs receive special rate and regulatory treatments, including the ability to sell capacity and energy to utilities. All utilities, regardless of ownership structure, must interconnect and sell back-up power to a QF, as well as purchase energy or capacity or both from the QF. This requirement applies not only to the large investor-owned utilities in South Carolina, but to all load-serving entities. These obligations are waived if the QF has non-discriminatory access to competitive wholesale energy and long-term capacity markets. As South Carolina does not have a deregulated, competitive, wholesale energy and capacity market structure, the obligations are in effect in the state.

7.1.2 AVOIDED COST METHODOLOGY

PURPA states that purchase rates by electric utilities must be "just and reasonable to the electric consumers of the electric utility and in the public interest."[63] The Federal Energy Regulatory Commission (FERC) is the federal agency that has the responsibility to implement and enforce PURPA. FERC established the term "avoided cost" to describe these purchase rates and defines avoided cost as "the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source."[64]

In Order 69, FERC divides avoided costs into two components: avoided energy costs and avoided capacity costs.[65] Energy costs are the variable costs associated with the production of electric energy and typically consist of the cost of fuel and certain operating and maintenance costs. Capacity costs are the costs associated with providing the ability to deliver energy and typically consist of capital costs of facilities.

Under PURPA, state public utility commissions have the authority to determine the appropriate methodology for calculating avoided cost rates. Some commissions are fairly prescriptive as to the methodology utilities within their state must use, while others permit the utilities to employ various calculation approaches. The South Carolina PSC allows utilities considerable discretion in selecting and executing their methodology. Historically, a variety of methodologies have been used by commissions and utilities to calculate avoided costs. These methods include the following: Proxy Resource Method, "Peaker" Method, Partial Displacement Differential Revenue Requirement Method (DRR), Fuel Index rates, and Auction/RFP rates.[66]

The theoretical goal of an avoided cost calculation is to make a utility indifferent to purchasing capacity and energy from a QF resource versus building a utility-owned resource or contracting explicitly for one. In an environment in which potential QF resources have a significant impact on the utility's plans, this calculation can be extremely challenging to carry forward because it is difficult to know how much QF

[63] Public Utility Regulatory Policies Act of 1978, 92 Stat. 3117; U.S.C. § 2601 (1978). Page 3157

[64] *National Association of Regulatory Utility Commissioners. PURPA Title II Compliance Manual. By Robert E. Burns and Kenneth Rose. N.p.: n.p., 2014.* Page 33. https://pubs.naruc.org/pub/B5B60741-CD40-7598-06EC-F63DF7BB12DC

[65] "Small Power Production and Cogeneration Facilities; Regulations Implementing Section 210 of the Public Utility Regulatory Policies Act of 1078." 45 Federal Register 38 (25 February 1980), pp 12214 - 12237.

[66] For brief descriptions of these calculation methods see the National Association of Regulatory Utility Commissioners (NARUC) PURPA Title II Compliance Manual.

resources the utility can expect to come online, and how much to rely on not-yet-built QFs to provide reliable capacity and energy resources in future years. It can be difficult, if not impossible, for QFs to get financing without guarantees that they will have a long-term purchase agreement for the power generated. Thus, while PURPA provides an avenue for smaller scale renewable resources to enter the market, there are important considerations in relying on PURPA-defined avoided costs to compensate and plan for significant amounts of new, non-utility generation.[67]

The calculation of avoided costs is a nuanced process, with fairly distinct methodologies between states and utilities. Yet the outcomes of this process have wide-ranging effects on non-utility resources, from small-scale customer-generators (whose ascribed value is ultimately tied to utility- and commission-established avoided costs) to large, utility-scale facilities connected directly to the transmission system. In South Carolina, utility-scale solar developers find the lack of guaranteed contract lengths in some service territories, as well as the values derived from at-times disputed avoided cost methodologies, to be significant impediments to what they consider otherwise viable potential projects.

Given the complexity of the avoided cost calculations and the impact the resulting values have on a variety of resources, various stakeholders in the Act 236: Version 2.0 discussions have indicated their belief that South Carolina should introduce additional oversight into this process. Numerous other states empower their public service commissions with considerable staffing support for reviewing and discussing avoided cost calculations and results; bolstering this type of support for the South Carolina PSC could allow for a more transparent and inclusive process for establishing the value of non-utility resources.

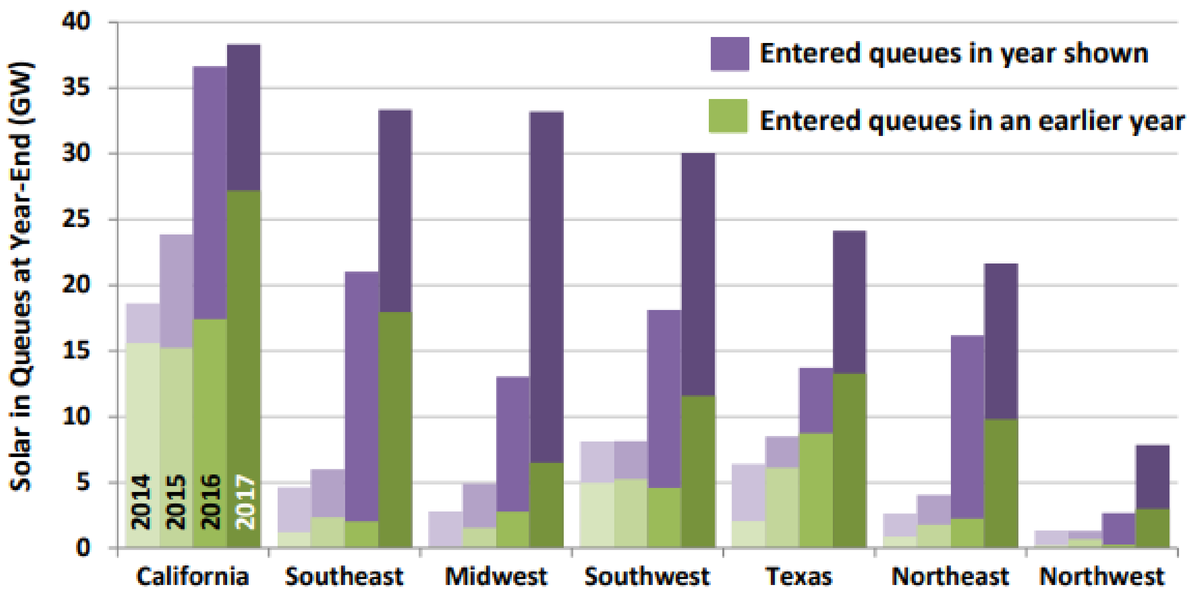
7.2 Interconnection

Generator interconnection is a complex process governed in different circumstances by either state or federal law. State-jurisdictional interconnection requests fall under the South Carolina Generator Interconnection Procedures (SCGIP) approved by the South Carolina PSC, while interconnection requests under federal jurisdiction are governed by FERC. These processes are not only for renewable generation, but also for any generator requesting interconnection to a utility's transmission or distribution system.

Across the country, the amount of planned capacity entering interconnection queues has grown substantially in the past several years, especially for solar projects. As seen in Figure 10, the Southeast is no exception, and in fact it has seen some of the most dramatic year-over-year solar growth of all regions between 2015 and 2017.[68]

[67] One stakeholder notes that another important consideration for policymakers is whether long-term QF contracts force customers to pay more for QF power than what they would otherwise pay in the spot market for energy, given that the utilities' retail customers are the ones who ultimately pay for the contracts entered into under PURPA.
[68] LBNL, Utility Scale Solar Report 2018.

Figure 10. Solar Capacity by Region in 35 Selected Interconnection Queues



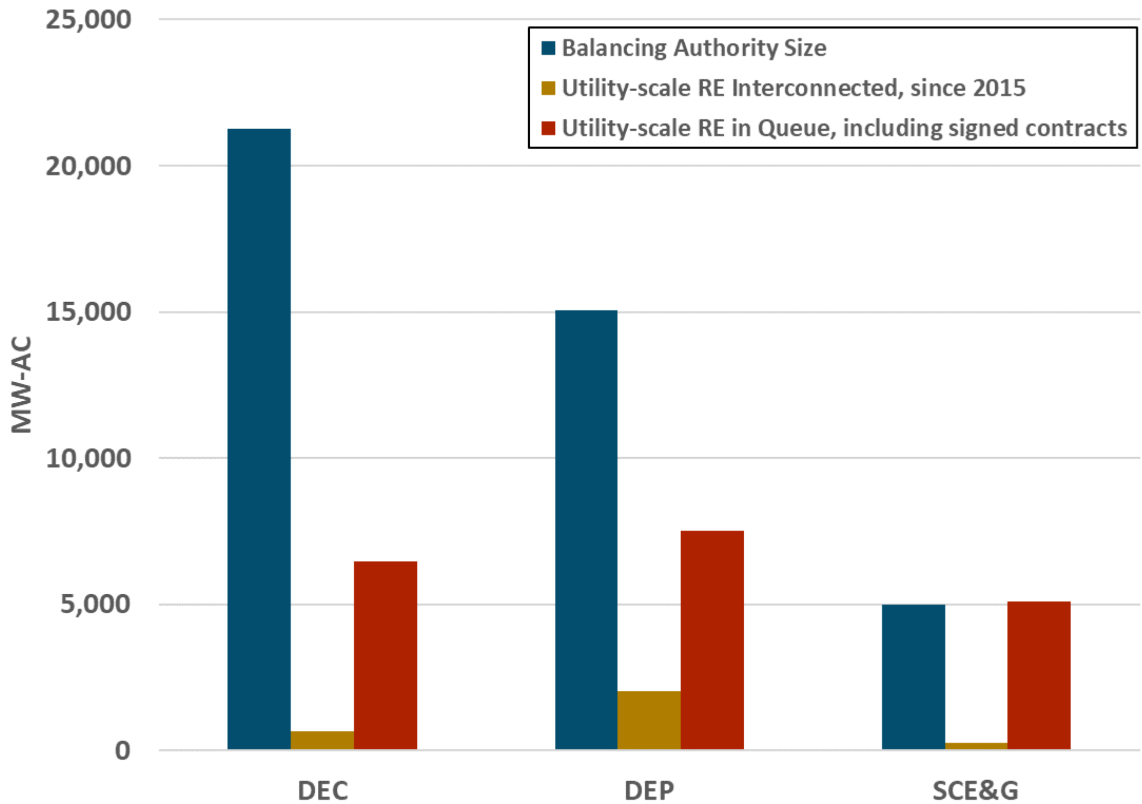
Source: Exeter Associates review of interconnection queue data

Figure 11 provides a more specific look at the size of the three large IOUs in South Carolina, relative to both the amount of renewable energy interconnected since 2015 and renewable energy currently in the interconnection queue. Note that the figures for DEC and DEP include both South Carolina and North Carolina, given that both utilities operate their respective systems in both states as uniform electric systems (often referred to as balancing authority areas).[69,70]

[69] This figure does not report the amount of non-renewable capacity requesting interconnection, which the utilities report as being a significant aggregate amount. These requests have important ramifications for renewable generators requesting interconnection, given the need for additional system studies and potential upgrades.

[70] This figure shows interconnection queues in nameplate capacity. Given that renewable generators have fairly low capacity factors, the relationship between balancing authority size (load or demand) and the cumulative size of interconnecting projects can be misleading, as it implies that the amount of renewable capacity recently interconnected – and especially the amount in the queue to interconnect – represents a much larger proportion of the total utility balancing authority than it can realistically be expected to serve.

Figure 11. South Carolina Large IOU Size, Relative to Renewable Capacity Interconnections



Given the unprecedented demand for interconnection to the electric grid, existing processes may need to be revisited and optimized to better accommodate both the increasing number of requests to interconnect and the aggregate capacity they represent. In doing so, however, it is essential to maintain adequate safety and reliability standards to ensure that projects connecting to the electric grid can be integrated without causing adverse effects.

Interconnection standards are intended to establish clear, consistent processes by which non-utility energy resources may connect to the electric grid. Transparent requirements and processes designed to account for and accommodate all applicable energy resources ensure the safety and reliability of the electric grid, while also limiting the need for expensive and time-consuming custom reviews.

The Interstate Renewable Energy Council (IREC) provides a useful set of "best practices" for interconnection standards, identifying areas in which processes can be optimized and inefficiencies can be eliminated.[71] Here we briefly highlight the main themes of the IREC practices, which are described at

[71] "Priority Considerations for Interconnection Standards: A Quick Reference Guide for Utility Regulators." (2017). and "Model Interconnection Procedures." (2013). Interstate Renewable Energy Council.

greater length in the Appendix (see section 9.5), along with an evaluation of South Carolina's Generator Interconnection Procedures (SCGIP) relative to these IREC recommendations.

- Ensuring all parties adhere to established **timelines to promote efficiency** through the interconnection queue (e.g., clearing queues of stalled projects, utilizing online applications);
- **Transparency** throughout the process to allow interconnecting parties **visibility into the progress of their projects** and enable resolution of outstanding issues (e.g., providing project status updates or an online status portal);
- Establishing an **effective dispute resolution process** to allow for mediation to avoid stalled projects and backlogged queues (e.g., involving third-party engineers to resolve technical disputes);
- Incorporating **enforcement mechanisms to ensure utility compliance** with timelines and process requirements (e.g., rewarding or penalizing utility performance based on customer satisfaction with the interconnection process).

7.2.1 INTERCONNECTION IN SOUTH CAROLINA

The issues that large-scale solar developers in South Carolina highlight as the biggest impediments to their projects, relative to interconnection practices, include queue timeline delays and the lack of mechanisms to enforce utility timeline compliance, as well as the absence of a clear dispute resolution process.[72] In turn, a key issue that utilities highlight is the lack of response timelines for developers when being asked to provide additional information for the utility to complete studies or to provide decisions when multiple interconnection options are available for the developer. Utilities also note delays driven by disputes; the number, nature and complexity of the projects and their relation to each other; and related federal actions. While the SCGIP requires utilities to submit semi-annual reports and post online monthly updates on their interconnection queues, it does not include any penalties should queue status deviate significantly from the established timelines for each step of the application process. This is problematic for developers, who have little recourse for moving projects forward when these timelines are not met. One utility stakeholder notes that the studies to evaluate each interconnection request often present unique challenges, as the utilities must ensure reliability while interconnecting unprecedented levels of intermittent, non-dispatchable solar generation to their system.

Section 6.2.3 of the SCGIP states that if no resolution has been reached within ten business days of one party providing the other with a written notice of dispute, the ORS may be contacted by either party "for assistance in informally resolving" the disagreement. If this informal process fails, either party may then file a formal complaint with the PSC. While a dispute resolution role is therefore nominally codified in the standard, in practice this component of the SCGIP remains underutilized, given that the ORS has no enforcement authority. To date, few formal complaints have been filed.[73]

[72] Throughout the Act 236 2.0 process, utility-scale solar developers have indicated that their issues in South Carolina have predominantly been when interconnecting to Duke's system, rather than that of SCE&G.
[73] One utility-scale solar developer has noted their hesitation to file formal complaints with the Commission against the utilities for timeline delays, given concerns that doing so may jeopardize their other projects waiting in the queue for processing by the same utilities. A utility stakeholder finds this insinuation to be inflammatory and baseless, questioning what the implied "retaliation" would even look like.

As suggested by IREC, monetary penalties for interconnection delays provide one potential avenue for more efficient project processing. Notably, these penalties need not apply solely to utilities, but can also serve as an incentive for developers to complete necessary steps adequately and on time.

Finally, recent legislation in North Carolina merits attention relative to interconnection in South Carolina. NC House Bill 589 of 2017, also known as "Competitive Energy Solutions for NC," established a competitive bidding program for renewable energy – Competitive Procurement of Renewable Energy (CPRE) – as well as a solar deployment target of 6,800 MW by 2020.[74] Given that projects in South Carolina are eligible to participate in this program, there will likely be considerable interest in bidding into the competitive process; subsequently, there could be a potentially significant increase in interconnection requests in South Carolina. As this develops, it will be important for South Carolina to ensure older projects holding more advanced queue positions are treated equitably, even if the interconnection process is amended to accommodate an influx of CPRE projects.

[74] https://www.ncleg.net/Sessions/2017/Bills/House/PDF/H589v6.pdf

8 Areas for Further Consideration

Key Takeaways

- The Act 236 version 2.0 stakeholders have made progress on several important questions regarding South Carolina's near-term energy future.
- Considerable ongoing **attention is neede**d to design a **robust and dynamic electric system that can take advantage of new technologies, while minimizing costs for customers**.
- Several key areas to consider in this ongoing discussion include the potential for **holistic rate design**, how to best **modernize the grid**, and the design of a comprehensive and truly **integrated resource planning** process.

When considering the future of distributed and renewable resources in South Carolina, a core challenge is agreeing upon what the future of the electricity system will (and should) look like. Ideally, policies implemented in the short-term are flexible and will accommodate uncertain future scenarios, such as changing resource or technology costs, and can allow a market system to guide development. Creating such a "future-proofed" system requires considering issues from as holistic of a perspective as possible.

In this section, we briefly highlight several key issues related to the topics discussed by the Act 236: Version 2.0 group. While deemed outside of the feasible scope of the current process, these topics are nonetheless an important piece of a comprehensive energy future for South Carolina.

8.1 Holistic Rate Design

As discussed in the *Rate Design* section, properly aligning retail electricity prices with underlying costs and creating a compensation and revenue collection framework indifferent to technology is the most economically efficient approach. While the feasibility and implementation pathways for this option can, will, and should be debated, this approach will ultimately better align costs and benefits – for both DER and non-DER customers – than incremental or short-term adjustments to rate design. It also accommodates resources that are beginning to appear on electricity systems across the country, such as electric vehicles and energy storage.

Such a fundamental change to rate structures is well beyond the charge of the Act 236: Version 2.0 stakeholder group. Nonetheless, policymakers and other stakeholders should keep the option of broader retail rate restructuring in mind as the state's energy planning evolves. If and when more comprehensive retail rate design changes are contemplated, the ratemaking principles and compromises described in this report's *Rate Design* section should be considered.

8.2 Grid Modernization

While related to many of the considerations of the Act 236: Version 2.0 stakeholder group, doing justice to the topic of grid modernization would require significantly broadening the scope of the stakeholder group's charge, as it extends far beyond the focus of DER programs and issues raised by the original Act 236. In short, as energy resources and technologies evolve, grid infrastructure may need to adapt to effectively deploy and fairly compensate the full suite of technologies and capabilities that will be a part of the 21st century electric grid.

Similar to the fundamental rate design questions discussed briefly above, the proper manner by which to modernize the grid in South Carolina – and how to treat the costs of doing so – is an important consideration. The utilities in South Carolina, and especially DEC and DEP, have already proposed grid modernization plans for the state. The Duke utilities have been hosting "Grid Improvement Workshops" in recent months, attended by some of the same stakeholders as the Act 236: Version 2.0 group. Collaboration between all involved parties will be critical to achieving any consensus around cost-effective infrastructure upgrades, which may provide significant future benefits but may also involve substantial investment in the near term.

8.3 Integrated Resource Planning

Underpinning many of the issues discussed in this report is the broader context behind electricity system planning. Historically, integrated resource plans (IRPs) have been used by utilities and system operators to plan for supply-side resources in traditional vertically integrated market structures. As technologies and market structures evolve, IRP planners are facing a new set of challenges. Some of these challenges, especially relevant to DER technologies, include the following: whether to treat DERs as load modifiers or as system resources; how to treat interactions between bulk system investments, retail rates, and DER adoption; and to what extent DER technologies and programs capture local, in addition to bulk, system value? These are important considerations that should be addressed in a holistic manner, as they will have a strong effect on designing appropriate rate structures for solar as well as other DERs, including storage and electric vehicles. The table below summarizes E3's view on emerging best practices in utility resource planning.

Table 3. E3 View on Emerging Best Practices in Utility Resource Planning

Issue	Key Resource Planning Challenges	Emerging Best Practices
Accelerated Baseload Generation Retirements	• Should utilities accelerate retirements of baseload (e.g. coal or nuclear) units, and if so, by when and on what basis? • If utilities accelerate retirements, how should they replace the capacity and energy of these units?	• Developing an analytical basis for decision-making, balancing optimization with simpler screening analysis
CO_2 Pricing	• How should CO_2 price uncertainty best be dealt with in resource planning?	• Incorporating full range (high and low) of meaningful CO_2 prices into portfolio development and portfolio risk analysis • Developing shared understanding and intuition for how different CO_2 price levels affect investment and operating decisions
Distributed Energy Resources	• Should DERs be treated as load modifiers or resources in planning models? • How can responsive loads be most accurately represented in expansion models? • How should adoption of DERs be forecast, and how can interactions among bulk system investment decisions, retail rates, and DER adoption be best captured? • To what extent should DER programs be targeted to capture local system values?	• Incrementally improving analysis tools for DERs, while balancing tradeoffs among modeling accuracy, impact on outcomes, and staff and materials costs
Wind and Solar Generation	• How should investments in wind and solar generation be determined? • How should wind and solar variability and uncertainty be accounted for in planning models? • Should wind and solar generation be assigned capacity value, and if so, how and how much?	• Treating wind and solar as selectable resources in capacity expansion models • Stochastic modeling of wind and solar in capacity expansion and production simulation models to better capture integration costs • Undertaking reliability analysis to assign incremental capacity value to wind and solar generation and determine overall capacity and energy needs
Energy Storage	• How should the benefits of energy storage be captured in planning analysis?	• Exploring strategies to include a broader range of storage values in planning
Uncertainty and Risk	• How should utilities incorporate and manage uncertainty in their planning processes? • How should utilities and regulators incorporate quantitative risk assessment into investment decision-making and oversight?	• Using multiple well-designed scenario analyses to develop several resource portfolios that capture a meaningful spectrum of “what if” questions • Using sensitivity analysis to develop risk-adjusted cost metrics • Establishing trigger points for emerging demand-side technologies

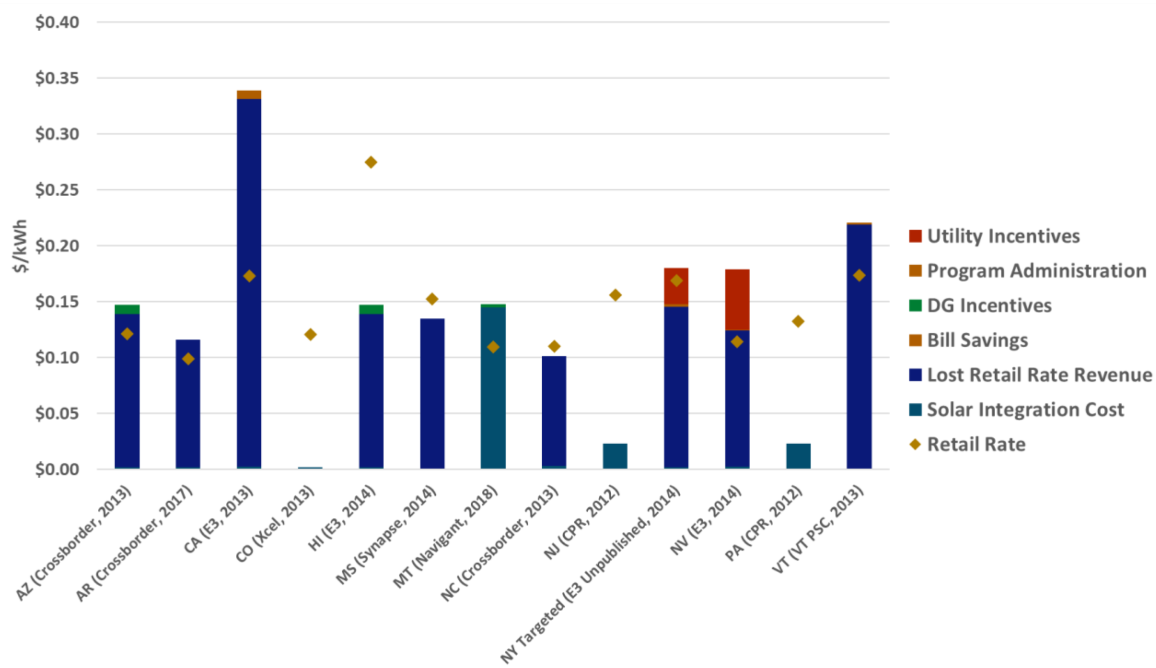
9 Appendix

9.1 Value of DERs – Additional Examples

9.1.1 QUANTIFYING COSTS IN VALUE OF SOLAR STUDIES

As described in the Value of DERs section of the main report, Value of Solar or Value of DER studies more commonly quantify benefits than they do costs. Figure 12 below highlights the costs quantified by a handful of studies that looked at both benefits and costs associated with DERs.

Figure 12. Value of Solar - Costs



9.1.2 UPDATING ZERO-VALUES

Different jurisdictions utilize a variety of methods for calculating the avoided cost components currently assigned a zero-value in South Carolina. Table 4 summarizes two recent studies with fairly divergent results, which serve as useful examples of alternative approaches to calculating the placeholder values.

Table 4. Two Approaches to Evaluating the Value of Specific DER Components

Component	Maryland, 2018[75]	Montana, 2018[76]
Ancillary Services	Not calculated, given complexity of calculations and difficulty in deriving accurate results. **Value: N/A**	Not calculated, considered to be subjective and not quantifiable. **Value: N/A**
Transmission & Distribution Capacity	*Transmission*: Reviewed planned transmission upgrades and assessed value of deferring projects for two years (a "reasonable balance relative to time deferral and a reasonable indication of the impact" on transmission rates). *Distribution*: Used results of pilot program to baseline distribution upgrade deferral value due to solar installation; combined with location-specific values to estimate specific locational benefits. **Value: $0.003/kWh**	Site-specific marginal cost data from utility resource plans used to assess specific capacity additions that can reasonably be deferred by firm NEM solar capacity. **Value: $0.002/kWh**
Avoided CO_2 Emissions	Estimated using combination of solar generation forecasts and forecast value of CO_2 emissions allowances through the Regional Greenhouse Gas Initiative (RGGI). **Value: $0.015/kWh in 2020; $0.025/kWh in 2028** **[Reference scenario]**	CO_2 price forecast developed and paired with average bulk power system carbon emissions intensity values to derive anticipated reductions under different solar adoption scenarios. **Value: Embedded in avoided energy value**
Fuel Hedge	Three approaches proposed, but no value included: 1) Assessed change in mean and standard deviation of per MWh cost of market portion of utility portfolio. 2) Assessed change in exposure to tail risk[77] as measured by Conditional Value at Risk. 3) Assessed change in shape of market exposure (as measured by exposure to outcomes above / below target market portfolio cost). **Value: N/A**	Not calculated (assumption was that solar adoption will remain small enough to have little effect on fuel price hedging).[78] **Value: N/A**
Utility Integration & Interconnection	Excluded from analysis (some costs assumed to be incurred by developer at time of project construction). **Value: N/A**	Excluded from analysis, given that the forecast amount of solar adoption is small enough that the utility is not expected to incur significant costs of this nature. **Value: N/A**
Utility Administration	Not assessed in analysis. **Value: N/A**	Developed based on an analysis of time and labor required per NEM application. **Value: $0.003**
Environmental	Estimated using combination of solar generation forecasts and forecast value of emissions allowance prices through the EPA Cross-State Air Pollution Rule program. **Value: Embedded in avoided energy value**	Assumed environmental compliance costs are embedded in avoided energy costs. **Value: $0.005/kWh**

[75] "Benefits and Costs of Utility Scale and Behind the Meter Solar Resources in Maryland." Prepared for Maryland PSC. Daymark Energy Advisors. April 2018.
[76] "NEM Benefit-Cost Analysis." Prepared for NorthWestern Energy – Montana. Navigant Consulting. March 2018.
[77] Tail risk is a type of portfolio risk, arising when the potential for an investment to move more than three standard deviations from the mean is greater than what a normal distribution would suggest.
[78] The Navigant Montana study references the ORS 2016 Act 236 Implementation report as one of several examples of how other jurisdictions also neglect to include a fuel hedging benefit in their valuation of DER. Given this circular logic, we note that this example alone should not be seen as reinforcement of the appropriateness of this approach.

These two studies highlight the considerable variation in methodologies that can be used to derive values for some of the current placeholder components in South Carolina. Additional approaches exist, and South Carolina may want to consider whether stakeholder consensus can be reached on an appropriate method to estimate the currently zero-value placeholders.

9.2 Existing LMI Energy Programs in South Carolina

9.2.1 LOW INCOME HOME ENERGY ASSISTANCE PROGRAM

The federal Low Income Home Energy Assistance Program (LIHEAP) is a block grant funded by the U.S. Department of Health and Human Services, providing funding assistance to economically disadvantaged households in order to help manage costs associated with home energy bills, weatherization and energy-related minor home repairs. The program is administered in South Carolina through local Community Action Agencies.

Given that LIHEAP is a capped block grant program, the funding it provides only serves a small percentage of the population eligible to receive the benefits it provides.[79] The latest LIHEAP Report to Congress indicates that South Carolina was allocated a net total of $38.9 million in 2014, with which 53,664 households were provided energy assistance.[80,81]

9.2.2 WEATHERIZATION ASSISTANCE PROGRAM

The Department of Energy's Weatherization Assistance Program (WAP) also provides low-income customers with home weatherization assistance. As with LIHEAP, in South Carolina this program is administered through local Community Action Agencies.

For fiscal year 2016, the South Carolina Office of Economic Opportunity (OEO) allocated a total of approximately $6.5 million to the Community Action Agencies through the WAP and associated LIHEAP WAP programs, weatherizing 312 homes representing 509 individuals and families, including many elderly and disabled funding recipients.[82] While state-level assessment data is not available, according to a

[79] "Approaches to Low-Income Energy Assistance Funding in Selected States." U.S. Department of Health and Human Services. March 2014.
[80] "Low Income Home Energy Assistance Program: Report to Congress for Fiscal Year 2014." U.S. Department of Health and Human Services. December 2016.
[81] An alternate estimate of LIHEAP eligibility vs. uptake is to assume similar eligibility as for SNAP. If 53,664 households received LIHEAP assistance in 2014, and 292,048 households received SNAP in 2018, roughly 18.4% of the SNAP recipient population received LIHEAP assistance. However, this approach doesn't account for the fact that not all SNAP-eligible residents participate in that program.
[82] "Weatherization Assistance Program." South Carolina Office of Economic Opportunity. February 2018. http://www.energy.sc.gov/files/view/2-12-2018%20Approved%20Weatherization%20Assistance%20Program_.pdf

national evaluation by the Department of Energy homes receiving WAP funding save on average $283 or more each year.[83]

OEO notes that in 2016 eleven states provided supplemental funding for the WAP, while forty states (including South Carolina) received additional WAP funding through local utilities and their ratepayers. In South Carolina, SCE&G, DEC, DEP, and several other utilities provide funding assistance for eligible individuals through Project SHARE and similar programs, where utilities match voluntary contributions from customers and employees.

9.2.3 COMMUNITY SOLAR FOR LMI CUSTOMERS

Both the existing SCE&G and the planned DEC and DEP community solar programs have specific allocations for LMI customers. These programs define LMI customers as those with annual income less than 200% of the poverty threshold.

The SCE&G program, which reached full subscription for all customers (both LMI and non-LMI) in October 2017, includes 1 MW of capacity specifically for LMI customers. There are currently 160 LMI customers enrolled in the program, implying an average capacity of 6.2 kW per customer. Using SCE&G's estimate of the energy produced by its community solar installations, LMI customers subscribed to this average system size would save approximately $114 each year.[84] SCE&G also requires LMI customers to complete a complimentary Energy Efficiency Home Energy Check-up prior to subscribing to the community solar program, which the utility estimates provides average annual energy savings of approximately 907 kWh (almost doubling the annual value customers would receive from their solar subscription alone).[85]

In their upcoming community solar programs, DEC and DEP will each be allocating 200 2-kW shares to LMI customers. While these customers will pay the same monthly charge as non-LMI customers, the application and initial fees will be waived. Based on these figures, we estimate that participating LMI customers in DEC and DEP will save approximately $62 and $68 each year, respectively.[86]

9.2.4 ADDITIONAL PROGRAMS IN SOUTH CAROLINA

One stakeholder noted a program administered in cooperative-served territories, which, while not specifically targeted toward LMI residents, has provided significant benefits to these customers. This energy efficiency retrofit program uses on-bill financing to provide customers that might not otherwise be able to afford efficiency measures the ability to invest in improvements, pay the loan through their bill, and benefit from net monthly savings. Another stakeholder noted that many utilities in South Carolina provide funding assistance for LMI customers through various energy efficiency programs available to all

[83] "Weatherization Assistance Program." U.S. Department of Energy. https://www.energy.gov/eere/wipo/weatherization-assistance-program
[84] SCE&G estimates solar production of 1,838 kWh/kW.
[85] Using SCE&G's standard Residential Rate 8 of $0.13652/kWh, this equates to approximately $124/yr.
[86] This estimate assumes 1,706 and 1,721 kWh/kW for DEC and DEP, respectively, based on Duke estimates of industrial customer solar system production. If instead the SCE&G estimate of 1,838 kWh/kW for community solar systems is used, the DEP and DEP savings estimates increase to $78 and $83 each year, respectively.

residential customers, in addition to energy efficiency and weatherization programs targeted specifically at assisting lower-income customers.

9.3 LMI Programs from Other Jurisdictions

States have taken a variety of approaches to providing energy assistance to LMI customers. The main categories include appropriations from state general funds, state-assessed surcharges on customers of regulated utilities (i.e., ratepayer funding), voluntary utility programs encouraging contributions from customers and employees, and charitable contributions funded by private nonprofit organizations, religious groups, or foundations.87 Several examples demonstrate potential options for South Carolina, should it decide to bolster support for the LMI population.

- In Florida, many of the local LIHEAP administrators augment federal funding through private sources, such as voluntary utility donation programs and nonprofit agencies.[88]
- California operates two LMI energy assistance programs funded through ratepayer surcharges, targeted at different income levels:
    - The California Alternative Rates for Energy (CARE) program provides a 30-35% discount on electricity bills and a 20% discount on natural gas bills.
    - The Family Electric Rate Assistance (FERA) program provides a smaller discount of 12% on electricity bills to families with incomes that slightly exceeds the thresholds of the CARE program.

Illinois offers a percent-of-income payment program (PIPP) to LIHEAP-eligible customers. Through this program, LMI customers pay a fixed percentage of their income towards their utility bill (in Illinois this is set at 6% of gross income) and receive a monthly LIHEAP benefit to cover the rest of the bill (up to a capped amount of $100/month).[89]

9.4 Update on Low- and Moderate-Income Issues

The following is a summary of a proposal made by the Low-to-Moderate Income Solutions subcommittee during the Act 236: Version 2.0 stakeholders meeting on October 9, 2018. The subcommittee included representatives from Appleseed Legal Justice Center and AARP.

The subcommittee noted that if low-income electric consumers were not given some relief, we did not have a true state energy plan, but an energy plan for those SC citizens who can pay for it. Their proposal was to create a statewide electricity bill program to provide some relief to very low-income residents, as

[87] Approaches to Low-Income Energy Assistance Funding in Selected States. U.S. Department of Health and Human Services. March 2014.
[88] Ibid.
[89] "Setting up utilities in the percentage of income payment plan." Illinois Legal Aid Online. Accessed 10/17/18. <https://www.illinoislegalaid.org/legal-information/setting-utilities-percentage-income-payment-plan>

determined by Supplemental Nutrition Assistance Program (SNAP) eligibility, managed by SC Department of Social Services. There are approximately 260,000 households eligible for SNAP benefits in the state, many of which consist of children, elderly, or disabled individuals. Families qualify for SNAP at 130% of the poverty limit. Poverty level is defined as $12,000 for individuals and $20,780 for a family of three.

The program would be funded through a per-kilowatt hour charge on all utility bills, and revenues collected would be rebated back to the SNAP-qualified customers via utility bills. This would be similar to the current telecommunications Lifeline program. This proposal would increase bills by approximately $2/month for a typical residential bill.

The suggested rebate or utility bill credit would be $50/month, requiring an estimated $164 million/year, or about $2/MWh of electricity used. The subcommittee suggested that IOUs would include this amount as an expense in filings before the PSC, with non-regulated utilities accounting for it as they do other business expenses. There was some discussion within the wider committee, with comments that perhaps the goal could be achieved at a lower cost.

The subcommittee noted that while they were fully supportive of energy efficiency efforts as well as solar, they felt that the most important work to be done immediately is to provide relief for low-income consumers. The subcommittee cited studies showing that low-income residents spend a disproportionately high percentage of their income on energy, not because of inefficient housing stock, although that is certainly a problem, but because incomes are so low that any high bill can be overwhelming. They also addressed the assumption that low-income families are usually high energy users; however, they cited data from the National Consumer Law Center and the U.S. Department of Energy's Energy Information Administration that showed a positive correlation between income and energy usage. Energy bills are a major cause of evictions or loss of housing, and these are already a major problem in some areas of the state.

Questions or points raised included:

- Can this proposal be done through a general tax to create a larger pool of funds?
- Does this proposal ask some customers to subsidize others?
- Are there examples of similar programs in other states?
- What percentage of those qualifying are in multifamily versus single family homes?

9.5 Interconnection "Best Practices" – the International Renewable Energy Council

9.5.1 TIMELINESS

- Interconnection **applications should be submitted online** and should incorporate electronic signatures to expedite processing.
- **Stalled projects** not meeting minimum progress requirements should be **cleared from the interconnection queue** to avoid excessive backlogs.

- Interconnection processes should **include timelines** for not only application processing, but also for **utility actions after applications have been approved**.
- **Efficient dispute resolution processes** should be implemented, such that developers utilize this option rather than waiting for application delays to pass.
  - In New York and Massachusetts, the Public Utilities Commissions provide ombudspersons to help resolve disputes.
  - In Minnesota, an ad hoc process involving outside engineers has been implemented to help mediate disputes.
  - For disputes over technical issues, a third-party "technical master" may be appointed to help resolve disputes in an impartial fashion.
- In addition to clear requirements of both utilities and developers throughout the process, interconnection standards should include **enforcement measures** to ensure **utility compliance**.
  - Massachusetts has instituted a "timeline enforcement mechanism" to impose monetary penalties on utilities if they fail to meet specified timelines.
  - New York adopted an "earnings adjustment mechanism" which rewards or penalizes utilities' performance on interconnection timelines based on customer satisfaction with the process.

9.5.2 TRANSPARENCY

- **Information** on **interconnection queues** and **project status** should be made available to project applicants and regulators to increase transparency and allow for better planning by developers.
  - In Massachusetts, the Department of Energy Resources collects interconnection queue data from utilities and publishes monthly updates on a public website.
- **Distribution system maps** showcasing features such as substations, line capacity, and existing generation capacity can **help developers to better assess** where **potential projects** are most likely to prove valuable.
  - ComEd provides useful maps for its Illinois service territory.
  - Utilities in New York provide maps highlighting good potential interconnection points.
  - In Delaware, Delmarva Power publishes a map of restricted circuits.
  - California's large utilities publish detailed maps with full hosting capacity information.
- For a small fee, utilities should provide **more granular information** on potential project sites via **pre-application reports**, leveraging pre-existing data and thus requiring limited effort to produce.
  - Many states have adopted pre-application reports, including South Carolina.

9.5.3 ADDITIONAL IREC RECOMMENDATIONS

- The interconnection process can be improved by **recognizing** the **specific values** and **services energy storage** can provide, given that this resource has distinct characteristics.
- Multiple **studies can be consolidated** into a single study to save time and expense. Following FERC processes, many states include three studies, one each for feasibility, system impacts, and facilities. However, many utilities and developers have found that the feasibility study is not necessary for each project, and further that the feasibility and system impact studies can be combined. **<u>SC and NC already doing this – feasibility study has been eliminated.</u>**
  - Minnesota, New York and Nevada consolidate system impacts and upgrade costs into a single study. This saves time, but also can leave project applicants having paid for a cost

estimate to be developed before learning of system impact results that likely halt the project.

- Determining and allocating necessary **upgrade costs** remains a challenge; IREC notes that best practices in this area have yet to be firmly established. However, striving to provide better estimates of **cost predictability**, **cost certainty**, and ultimate **cost allocation** should be an ongoing goal of well-functioning interconnection processes.
    - In Massachusetts, utilities must provide binding cost estimates. Final costs for projects cannot exceed 25% of estimated costs when estimates are requested early in the process; for estimates requested at the end of the review process, final costs cannot exceed the estimated amount by more than 10%.
    - California employs a similar process.

9.6 South Carolina's Interconnection Standard

The current South Carolina Generator Interconnection Procedures (SCGIP) were adopted by the PSC in April 2016, revised as required by the original Act 236.[90] Given the quickly evolving nature of the electric grid and the increasing demand for interconnection reviews, however, this standard may require further revision to accommodate the issues faced by the state.[91]

Table 5 summarizes South Carolina interconnection procedures relative to the IREC interconnection "best practices" detailed above in Section 9.6.

Table 5. Interconnection Practices in South Carolina, Relative to IREC Recommendations

Practice	SCGIP
Timeliness	
Online applications	✔[a]
Clearing queue of old projects	✗
Timelines for utility actions post-interconnection agreement signature	✗
Efficient dispute resolution process	✗[b]
Enforcement measures to ensure utility compliance	✗
Transparency	
Interconnection queue data availability	✔[c]

[90] PSC Order 2016-191 (Docket 2015-362-E).

[91] In this section we will focus on interconnection processes managed by South Carolina's utilities, and the interconnection standard established by the State, as opposed to standards published and overseen by FERC. While FERC maintains interconnection standards for several categories of generators connecting to the bulk power system, here we focus on South Carolina's utilities given that all in-state interconnections to the electric grid are within their jurisdiction.

Distribution system maps	✗
Pre-application reports	✓
Additional Considerations	
Recognition of specific values/services of energy storage	✗
Consolidation of studies to streamline process	✓ [d]
Cost allocation, certainty and predictability	✗

[a] SCGIP permits utilities to accept online applications but does not require that they do so.

[b] A dispute resolution process is briefly referenced in the SCGIP, but it does not follow IREC "best practices." Its effectiveness has been questioned by various Act 236: Version 2.0 stakeholders.

[c] SCGIP requires utilities to post monthly interconnection queue information on their websites, and to submit semi-annual queue reports to the PSC and ORS.

[d] SCGIP include a two-tier (system impact + facilities) study process, eliminating the separate feasibility study.

9.7 Methodology of Cost Shift Calculations

E3's estimate of the NEM cost shift from DER incorporated the following assumptions:

+ **Key Inputs**
  - The 2015-2018 cost shift estimate is based on historic installation data and approved avoided cost rates. Historic installation data was provided directly by the utilities.
    - Avoided cost rates for 2015-2017 were sourced from the 2017 ORS *Status Report on Distributed Energy Resource and Net Energy Metering Implementation*,[92] which reflects the respective tariffs approved in fuel testimony hearings.[93] The "Small PV" values were used for DEC and DEP.
    - Avoided cost rates for 2018 (and for the 2017 DEC value, which was not included in the 2017 ORS report) were taken directly from utility testimony in fuel proceedings.[94]
  - The estimated NEM cost shift for 2019-2025 relies on utility forecasts of customer-scale DER installations, as well as on utility expectations of avoided cost rates during those years.
    - The uncertainty surrounding installations and avoided costs is highlighted throughout both the estimated NEM cost shift analysis and the estimate of future total DER program costs.

[92] http://www.energy.sc.gov/files/view/FINAL%20DER%20and%20NEM%20Report%202017.pdf

[93] SCE&G: Docket Nos. 2015-205-E, 2016-2-E, 2017-2-E; DEC: Docket Nos. 2015-203-E, 2016-3-E; DEP: Docket Nos. 2015-204-E, 2016-1-E, 2017-1-E.

[94] SCE&G: Docket No. 2018-2-E; DEC: Docket No. 2018-3-E; DEP: Docket No. 2018-1-E.

- **General Assumptions**
  - Nominal discount rate of 7.6%
  - Annual retail electric rate escalation of 2.5% for all three utilities
  - The 2018 retail rates are current as of November 1, 2018 and are not adjusted for the proposed SCE&G-Dominion merger or the DEP and DEC 2018 rate cases.
- **Cost Shift Calculation**
  - In this report the NEM cost shift is calculated as the difference between the compensation received for generation from DERs via 1:1 bill crediting at the full volumetric retail rate, i.e., assuming full export and the established value of DER, specifically the avoided costs, to the utility's electric system. Note: this calculation reflects the DER NEM incentive as defined by the 2015 Settlement Agreement.[95]
  - The starting point for the NEM cost shift analysis is an estimate of annual generation from customer-scale systems in each utility's territory. This was calculated based on assumed generation figures provided by DEC and DEP.
    - DEP values were used to model generation from customer-scale systems in SCE&G territory.
    - Slightly different generation profiles were used for residential, commercial, and industrial customers.
  - The value (benefit) of this generation was assessed using the NEM Methodology established in the 2015 Settlement Agreement (actual for the historic period [2015-2018] and utility provided for the forecast period [2019-2025]).
  - The cost of this generation was assessed as the retail value of this generation.
    - Retail rates for the three utilities were represented as an average of relevant rates for a given customer class (residential, commercial or industrial) for each utility. E3 accounted for tiered pricing and seasonal variation in rates.

The difference between this calculated value and the calculated cost represents the estimated cost shift from NEM, as defined by the NEM Methodology established in the original Act 236 Settlement Agreement.

The below tables recreate the historical data sourced from each utility's fuel proceeding.

[95] Docket No. 2014-246-E, Order No. 2015-194.

Table 6. E3 Summary of Duke Energy Carolinas DERP Incremental Costs

Source: *DEC Fuel Testimony, 2015-2018*

DEC	Annual Totals ($MM)			
DERP Incremental Costs	2015	2016	2017	2018
Purchased Power Agreements	$0.00	$0.00	$0.00	$0.00
DER NEM Incentive	$0.00	$0.05	$0.97	$2.42
Solar Rebate Program - Amortization	$0.00	$0.03	$0.78	$2.32
Shared Solar Program	$0.00	$0.00	$0.00	$0.00
Carrying Costs on Deferred Amounts	$0.00	$0.03	$0.71	$2.25
NEM Avoided Capacity Costs	$0.00	$0.00	$0.05	$0.26
NEM Meter Costs	$0.00	$0.01	$0.11	$0.35
General and Administrative Expenses	$0.11	$0.88	$1.26	$0.58
Total DER Incremental Costs	**$0.11**	**$1.00**	**$3.88**	**$8.17**
DERP Avoided Cost - Energy & Capacity	$0.00	$0.00	$0.00	$0.00
Purchased Power Agreements	$0.00	$0.00	$0.03	$0.05
Shared Solar Program	$0.00	$0.00	$0.00	$0.00
Total DERP Avoided Cost	**$0.00**	**$0.00**	**$0.03**	**$0.05**
	$0.00	$0.00	$0.00	$0.00
Total Incremental and Avoided Cost	**$0.11**	**$1.00**	**$3.91**	**$8.22**

Table 7. E3 Summary of Duke Energy Progress DERP Incremental Costs

Source: *DEP Fuel Testimony, 2015-2018*

DEP	Annual Totals ($MM)			
DERP Incremental Costs	2015	2016	2017	2018
Purchased Power Agreements	$0.00	$0.00	$0.00	$0.00
DER NEM Incentive	$0.00	$0.01	$0.15	$0.69
Solar Rebate Program - Amortization	$0.00	$0.03	$0.37	$1.14
Shared Solar Program	$0.00	$0.00	$0.00	$0.00
Carrying Costs on Deferred Amounts	$0.00	$0.02	$0.34	$1.06
NEM Avoided Capacity Costs	$0.00	$0.00	$0.01	$0.03
NEM Meter Costs	$0.00	$0.00	$0.03	$0.04
General and Administrative Expenses	$0.60	$1.11	$0.60	$0.52
Interest on under-collection due to cap	$0.00	$0.00	$0.00	$0.00
Adjustments	$0.00	$0.00	$0.08	$0.00
Total DER Incremental Costs	**$0.60**	**$1.18**	**$1.57**	**$3.47**
DERP Avoided Cost - Energy & Capacity	$0.00	$0.00	$0.00	$0.00
Purchased Power Agreements	$0.00	$0.00	$0.03	$0.89
Shared Solar Program	$0.00	$0.00	$0.00	$0.00
Total DERP Avoided Cost	**$0.00**	**$0.00**	**$0.03**	**$0.89**
	$0.00	$0.00	$0.00	$0.00
Total Incremental and Avoided Cost	**$0.60**	**$1.18**	**$1.59**	**$4.37**

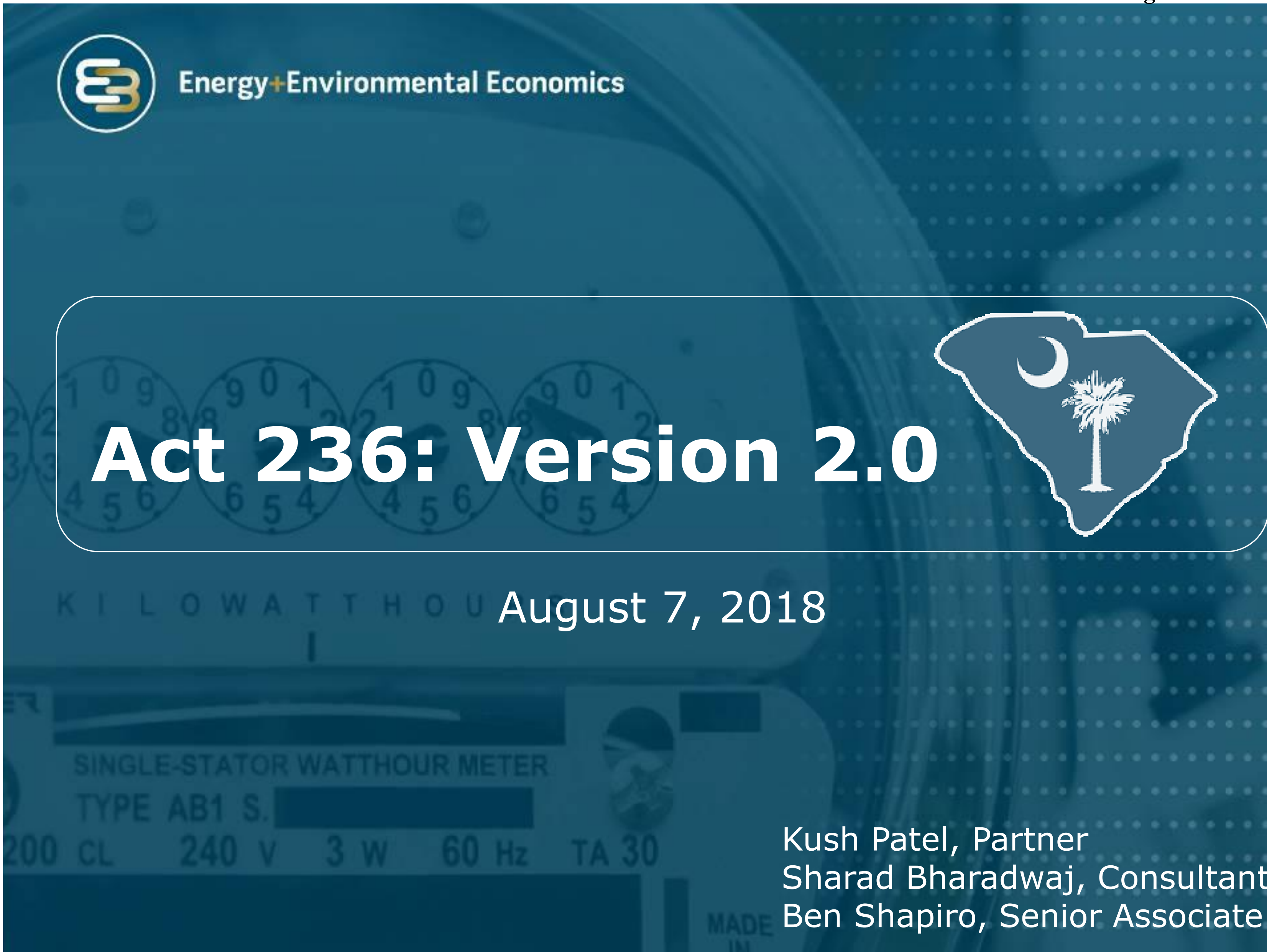
Table 8. E3 Summary of SCE&G DERP Incremental Costs

Source: *SCE&G Fuel Testimony, 2015-2018*

SCE&G	Annual Totals ($MM)			
DERP Incremental Costs	2015	2016	2017	2018
NEM Incentive	$0.01	$1.08	$4.43	$8.41
NEM Future Benefits	$0.00	$0.13	$0.15	-$0.01
NEM PBI	$0.00	$0.22	$0.31	$0.32
DER Depreciation Costs	$0.00	$0.07	$0.27	$0.41
BCA Incentive	$0.00	$0.08	$1.43	$3.76
Community Solar	$0.00	$0.00	$0.00	$1.42
Utility Scale Incentive	$0.00	$0.05	$0.43	$1.19
Administrative & General Expenses	$0.68	$1.35	$1.96	$1.97
Carrying Costs	$0.00	$0.06	$0.25	$0.59
Total DERP Incremental Costs	**$0.71**	**$3.05**	**$9.22**	**$18.06**
Revenue Recovery	$0.00	$2.89	$8.80	$3.70
Monthly (Over)/Under	$0.71	$0.15	$0.42	$14.36
Adjustments	$0.00	$0.00	$0.00	$0.00
Unbilled DERP Incremental Revenue	$0.00	-$0.18	-$0.32	$0.00
Balance at Period Ending	**$0.73**	**$0.70**	**$0.80**	**$15.16**

9.8 Selected E3 Presentations from Act 236: Version 2.0 Process

9.8.1 ACT 236 FOLLOW-UP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Act 236: Version 2.0
August 7, 2018
Kush Patel, Partner
Sharad Bharadwaj, Consultant
Ben Shapiro, Senior Associate

Agenda / Presentation Outline

- Introductions
- E3 Background
- Brief Discussion of Rate Design Principles in the Context of DER/Solar PV* Compensation
- Review of the Current "State of the Art" on Calculating the Value of Solar
- *State of the Union:* Summary of Relevant DER and Retail Rate Actions across the U.S.
- Next Steps
- Appendix

*Note distributed energy resources (DERs) and solar PV used interchangeably in this presentation

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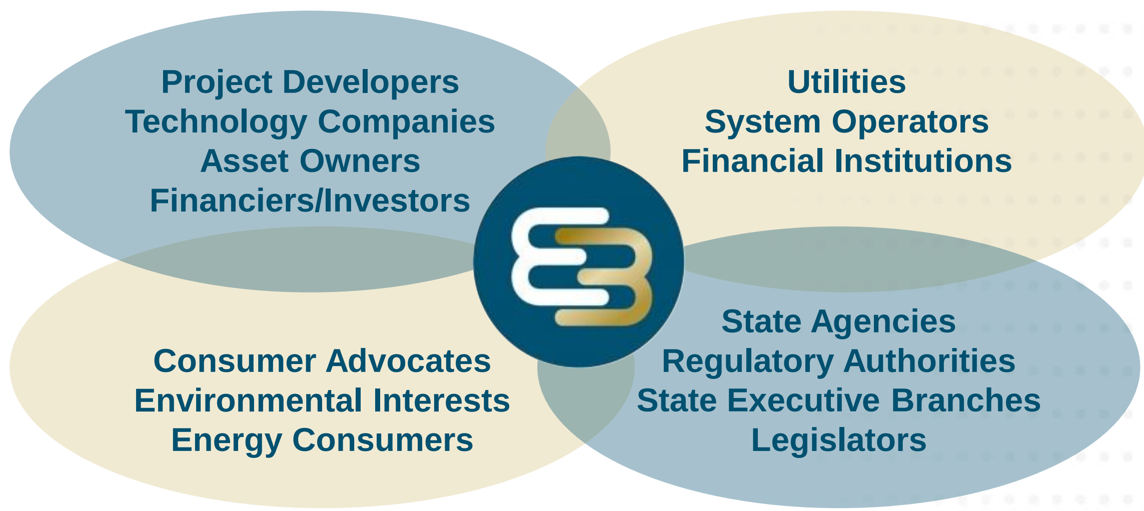
E3 INTRODUCTION AND BACKGROUND

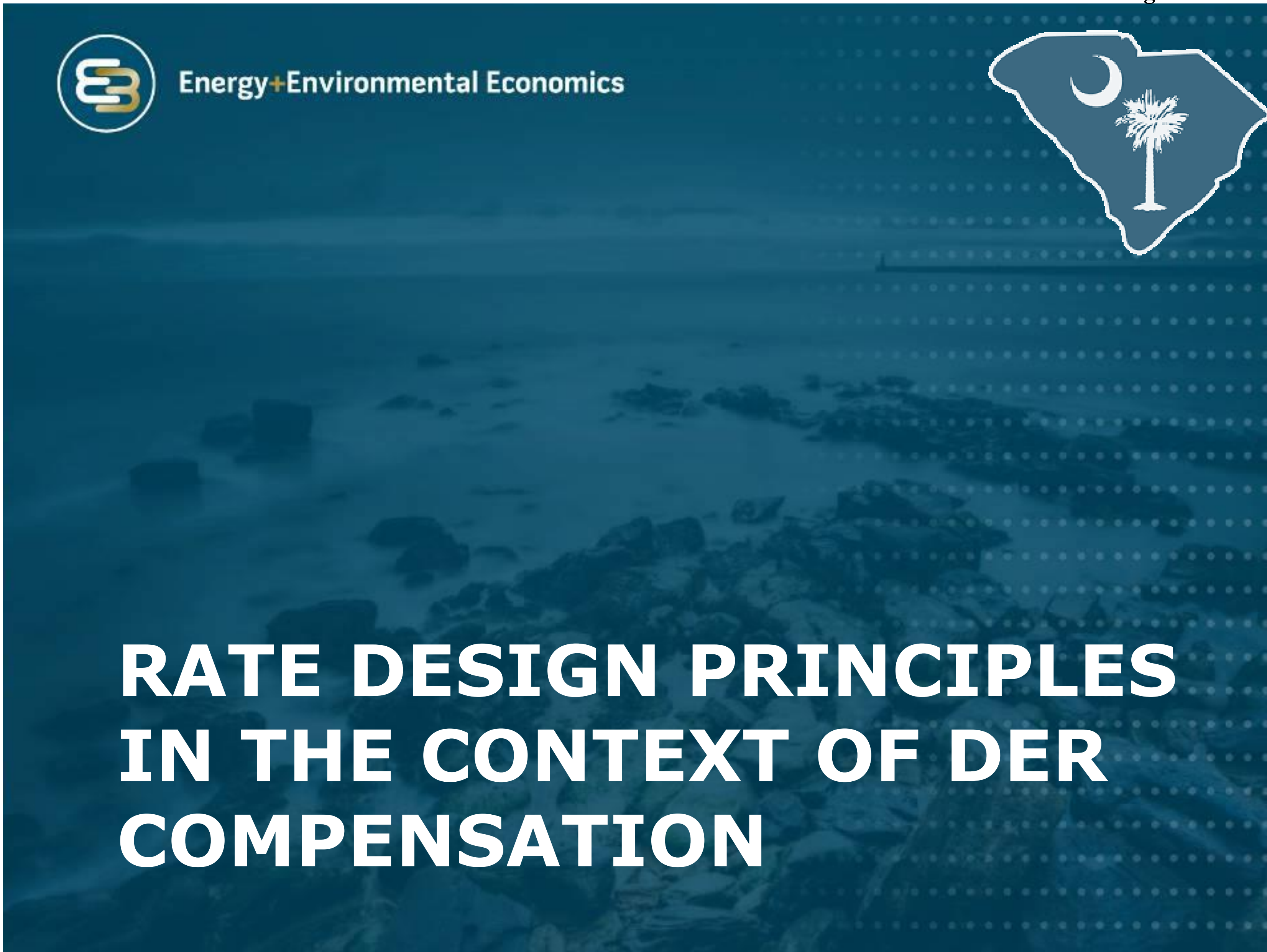
About E3:
We work across the industry and stakeholders

+ Founded in 1989, E3 is a leading energy consultancy with a unique 360 degree view of the industry
+ E3 operates at the nexus of energy, environment, and economics
+ Our team employs a unique combination of economic analysis, modeling acumen, and deep strategic insight to solve complex problems for a diverse client base



Who are we really and why we are here?

- E3 supported ORS and the stakeholders at the time to help reach the original Act 236 settlement agreement
- Since then we have supported ORS on Act 236 implementation and assessment as well as other issues, mostly involving avoided costs
- We are here again to support ORS and the stakeholders (old and new) to potentially reach another agreement on "Version 2" of Act 236
- We are extremely honored to be asked to help again on this extremely important topic and grateful for the time and financial support from all the stakeholders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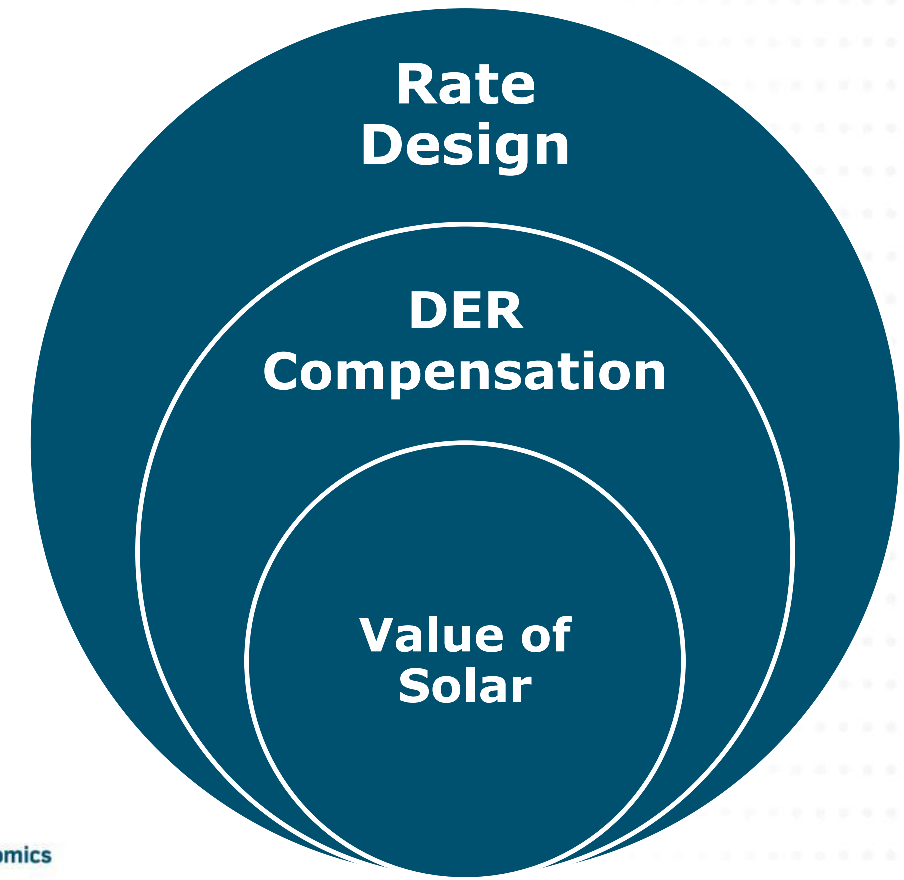
RATE DESIGN PRINCIPLES IN THE CONTEXT OF DER COMPENSATION

First Principle:

Rate design encompasses many issues; some of which are related, while many others are not

- **DER compensation and the value of solar are embedded issues within the larger set of general rate design concerns**



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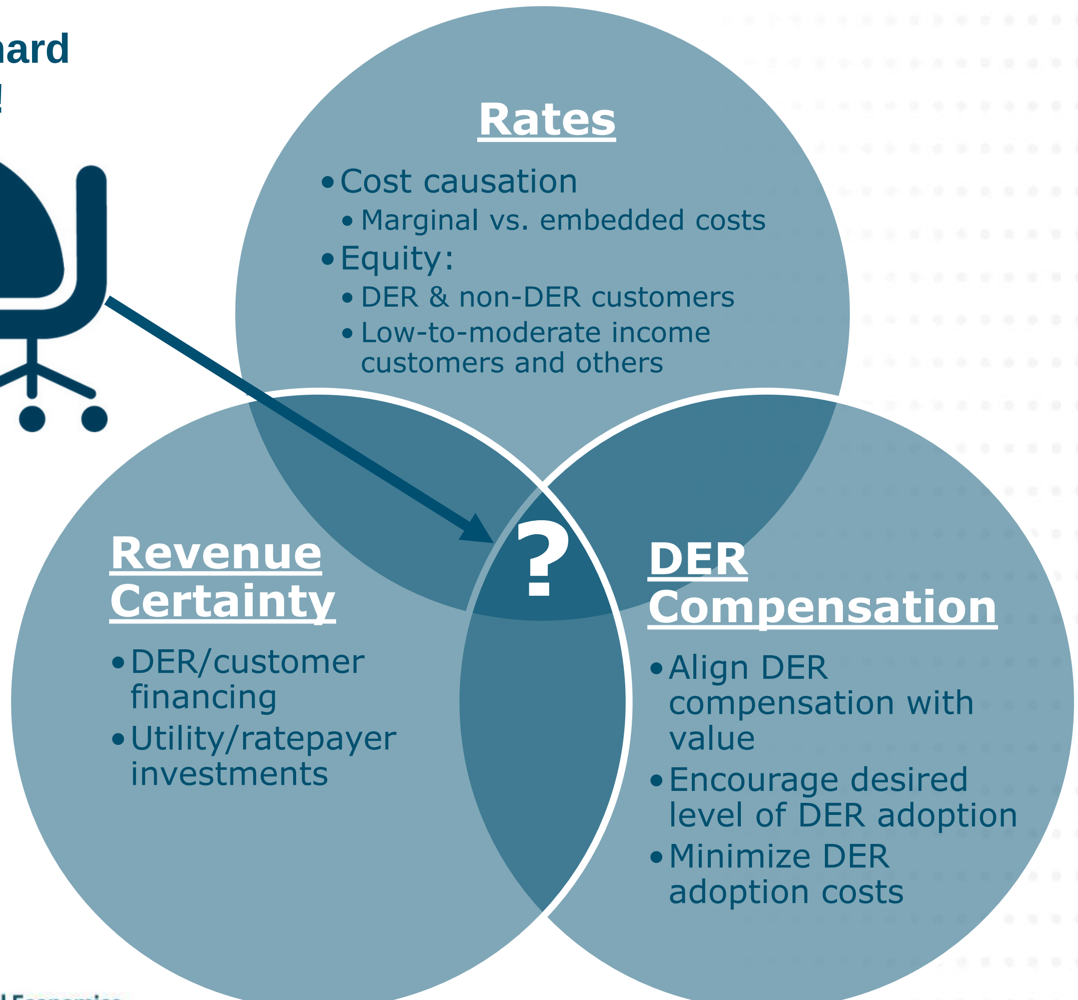
Second principle:
There is no perfect intersection between the "right" retail rate and the "best" type of DER compensation

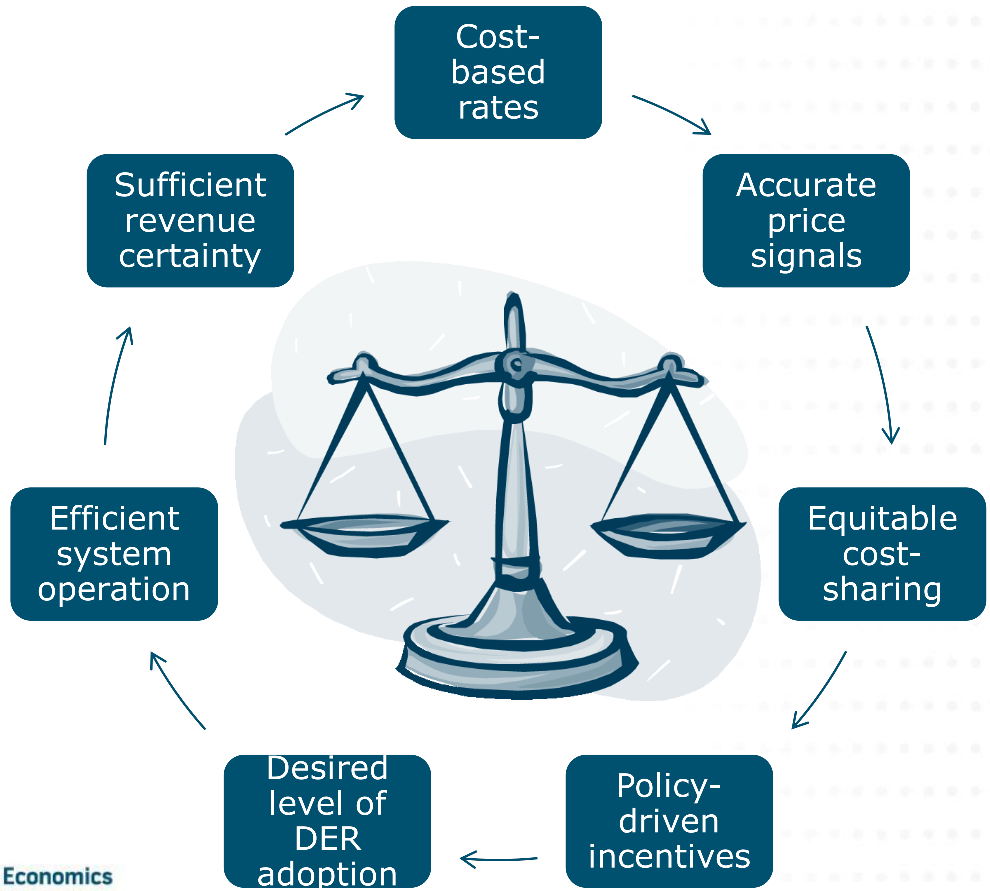
E3 will be hard at work!



Third Principle:

Compromise and balance is needed for equitable and sustainable DER compensation within rate design

+ ***Goal:*** **Retail rates and DER compensation mechanisms that accurately reflect South Carolina values**



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Here's one set of illustrative retail rate/DER compensation principles

- **Efficiency:**
  - Rates should promote efficient investment and consumption decisions by customers, which if tied to the utility avoided costs minimize the total costs of delivered energy to customers
- **Equity:**
  - Costs should be allocated fairly and equitably among customer classes and customers within the class when rate components are based on embedded costs
- **Rates should be simple, stable, understandable, acceptable to the public, and easily administered**
- **Innovative rate designs should be tested prior to full scale implementation**
- **Rates should support public policy, as applicable**

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CURRENT "STATE OF THE ART" WITH THE VALUE OF SOLAR

Summary of Value of Solar/DER benefits studies

Legend	
Included	•
Included as a sensitivity	•(s)
Represented/captured in other values	•(r)

EXAMPLES OF RECENT NEM VALUE STUDIES FROM STATES, UTILITIES, CONSULTANCIES, AND STAKEHOLDERS

STATE	STUDY	BENEFITS ANALYZED												COSTS ANALYZED				BENEFIT/COST TESTS							
		Avoided Energy (incl. O&M, fuel costs)	Avoided Fuel Hedge	Avoided Capacity (generation and reserve)	Avoided Losses	Avoided or Deferred T&D Investment	Avoided Ancillary Services	Market Price Reduction	Avoided Renewables Procurement	Monetized Environmental	Social Environmental	Security Enhancement/Risk	Societal (incl. economic/jobs)	PV Integration	Program Administration	Bill Savings (Utility Revenue Loss)	Utility/DER Incentives	Total Resource Cost Test (TRC)	Program Administrator/Utility Cost Test (PACT/UCT)	Cost of Service (COS) Analysis	Ratepayer Impact Measure (RIM)	Participant Cost Test (PCT)	Societal Cost Test (SCT)	Revenue Requirement Savings: Cost Ratio	Net Cost Comparison of NEM, FiT, Other
ARIZONA	Crossborder Energy (2013)	•		•	•	•	•	•(r)	•	•		•(r)	•(r)	•		•	•(s)				•				
ARIZONA	APS/SAIC (2013)	•		•	•(r)	•																			
ARKANSAS	Crossborder Energy (2017)	•	•		•	•				•	•		•	•	•	•	•	•	•		•	•	•		
CALIFORNIA	E3 (2013)	•		•	•	•	•		•	•				•	•	•				•	•				
CALIFORNIA	Crossborder Energy (2013)	•		•	•	•	•		•	•				•	•	•					•				
COLORADO	Xcel (2013)	•	•	•	•	•	•(r)			•				•											
HAWAII	E3 (2014)	•		•	•	•(s)	•				•(s)														•
MAINE	Clean Power Research (2015)	•	•	•	•(r)	•	•(r)	•			•			•											
MARYLAND	Daymark (2018)	•	•(s)	•	•(r)	•		•	•	•	•		•												
MASSACHUSETTS	La Capra Associates (2013)	•		•	•(r)	•		•	•	•		•(s)	•(s)			•	•	•			•				
MICHIGAN	NREL (2012)	•	•	•	•	•	•		•(r)	•															
MINNESOTA	Clean Power Research (2014)	•	•(r)	•	•	•					•														
MISSISSIPPI	Synapse Energy Economics (2014)	•	•	•	•	•				•				•	•	•		•				•		•	
MONTANA	Navigant (2018)	•		•	•	•				•(s)	•				•	•			•		•				
NORTH CAROLINA	Crossborder Energy (2013)	•	•	•	•(r)	•	•(r)	•(r)	•	•	•(s)	•(r)	•(r)	•		•	•								
NEW JERSEY	Clean Power Research (2012)	•	•	•	•	•		•	•(r)		•	•	•	•											
NEW YORK	E3 (2015)	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•		•	•	•	•		
NEVADA	E3 (2014)	•		•	•	•	•		•	•				•	•	•	•	•	•		•	•	•		
PENNSYLVANIA	Clean Power Research (2012)	•	•	•	•	•		•	•(r)		•	•	•	•											
SOUTH CAROLINA	E3 (2015)	•		•	•	•	•			•				•	•	•	•			•	•				
TENNESSEE	TVA (2015)	•		•	•(r)	•				•	•(s)														
TEXAS (AUSTIN)	Clean Power Research (2014)	•	•(r)	•	•	•			•(r)	•															
TEXAS (SAN ANTONIO)	Clean Power Research (2013)	•	•(r)	•	•	•				•															
UTAH	Clean Power Research (2014)	•	•	•	•(r)	•				•															
VERMONT	Vermont PSC (2013)	•		•	•(r)	•	•	•	•	•	•(s)				•	•					•				

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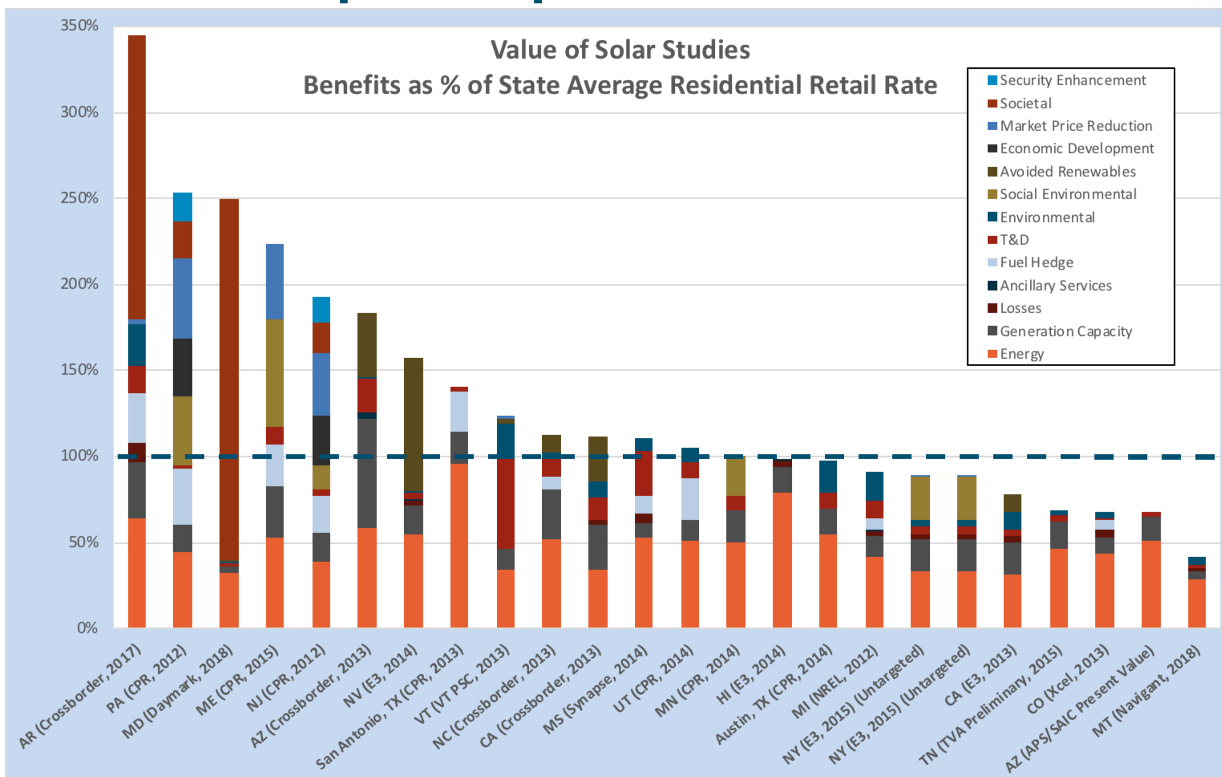
Value of Solar components

- Many potential value/benefit components for solar
- Which and how many components are analyzed has fundamental impact on perceived value of solar



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MD and MT Value of Solar studies are the most recent and wildly divergent

Maryland

Benefits
- Energy
  - +Market price reductions
- Capacity
- T&D
- Losses
- Carbon compliance
  - +NOx / SOx compliance
- Societal (economic, health, non-monetized carbon)
- Avoided fuel hedging
- Avoided REC compliance

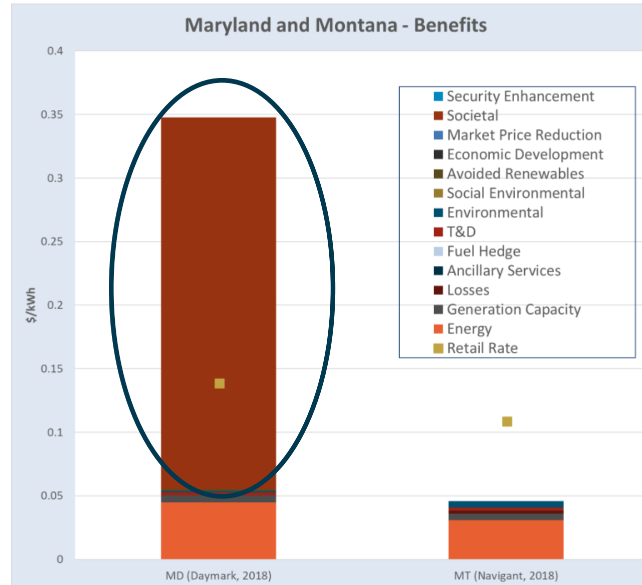
Costs
- Not considered

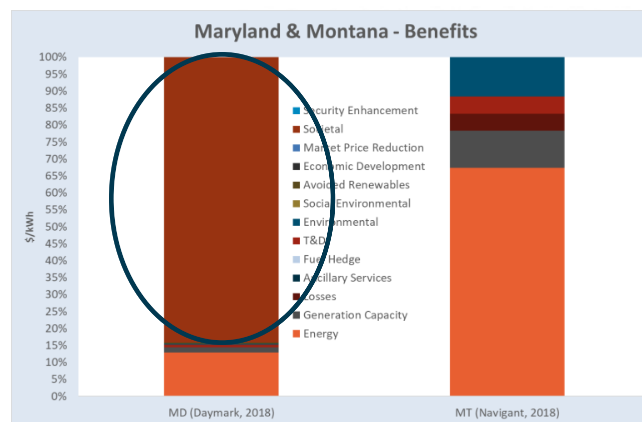
Montana

Benefits
- Energy
- Capacity
- T&D
- Losses
- Carbon compliance

Costs*
- Bill savings (lost utility revenues)
- Administrative

*Not shown in these charts, the costs calculated in the MT study total to $0.11/kWh





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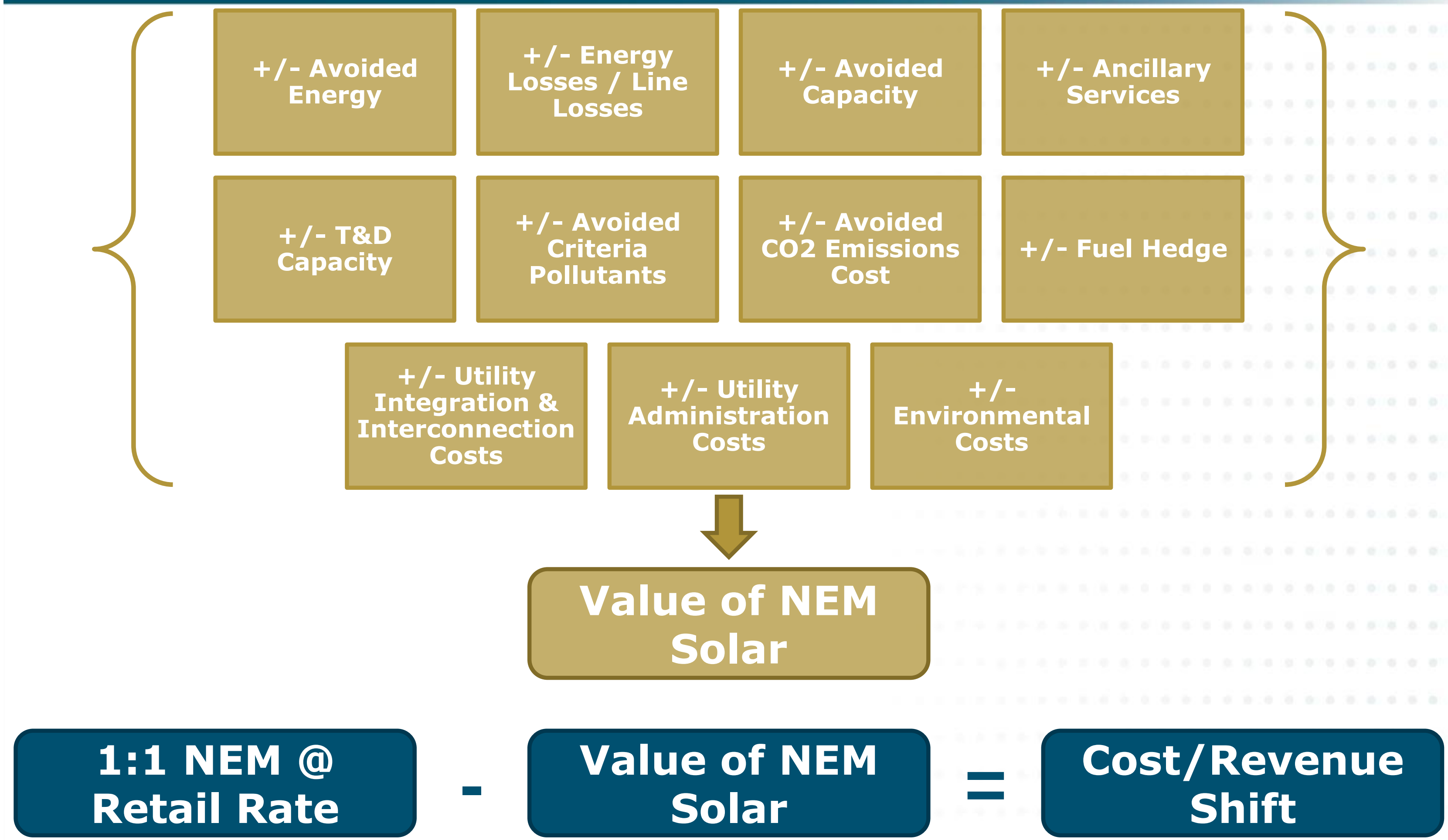
Reminder: Act 236 NEM Methodology



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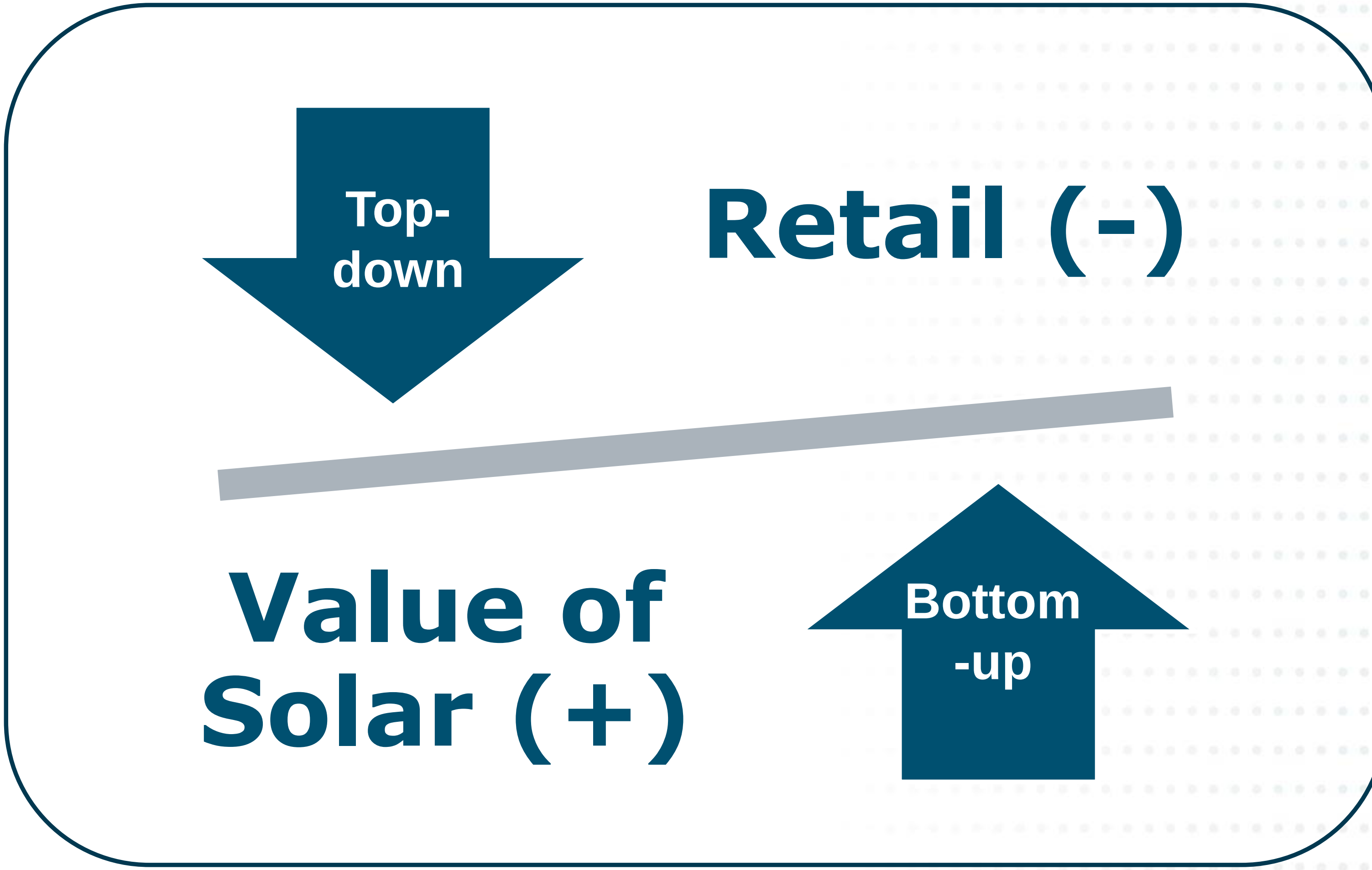
Ultimately there are two approaches to DER/solar compensation



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STATE OF THE UNION

Action on retail rates, DERs, and NEM is nationwide

Figure 1. 2017 Action on Net Metering, Rate Design, & Solar Ownership Policies

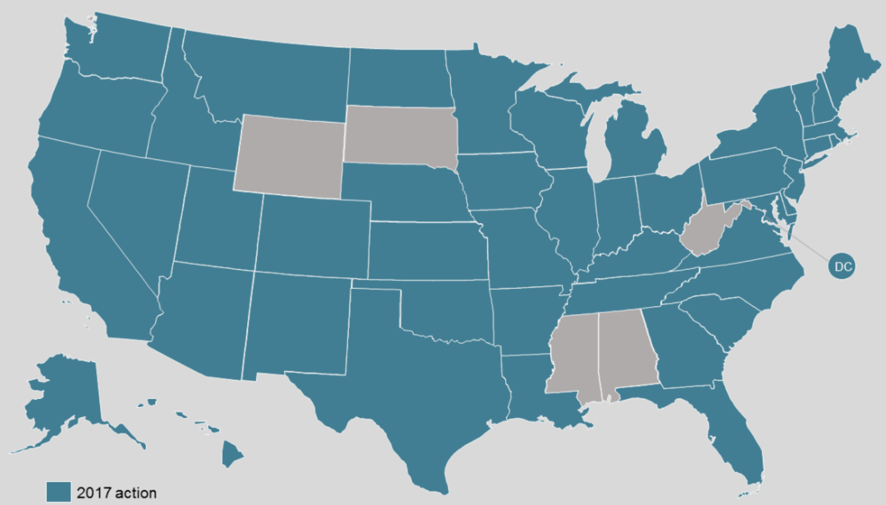

Table 1. Q2 2018 Summary of Policy Actions

Policy Type	# of Actions	% by Type	# of States
Residential fixed charge or minimum bill increase	46	31%	25
DG compensation rules	39	26%	23 + DC
Community solar	25	17%	17
DG valuation or net metering study	20	14%	16 + DC
Residential demand or solar charge	11	7%	5 + DC
Third-party ownership of solar	4	3%	2 + DC
Utility-led rooftop PV programs	3	2%	3
Total	**148**	**100%**	**42 States + DC**

Note: The "# of States/ Districts" total is not the sum of the rows, as some states have multiple actions. Percentages are rounded and may not add up to 100%.

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Image credit: North Carolina Clean Energy Technology Center

Majority of recent DER action is moving beyond NEM status quo

Maintaining the Status Quo
Nevada legislature restored statewide retail NEM
Florida PSC approved solar leasing
Transitions & Revisions
New York adopted more value-based compensation for certain types of DER
Hawaii revised NEM successor tariffs to encourage storage adoption
Maine legislature changed NEM to buy-all / sell-all structure (w/ decreasing credit value each year)
Arizona regulators replaced NEM w/ Net Billing at avoided cost
Utah regulators approved a Net Billing transition tariff (with rates slightly below retail)
Massachusetts DPU approved mandatory demand charge for residential DG customers
Idaho PUC permitted Idaho Power to create separate DG customer class
California mandated new homes post-2020 will be required to install solar
Connecticut legislature voted to replace NEM w/ a buy-all / sell-all rate structure
State regulators largely resisted utility-requested fixed charge increases (see Appendix for details)
Community Solar
Duke Energy (NC) and Dominion Virginia Power proposed / launched community solar plans

*Actions with which E3 is or has been involved

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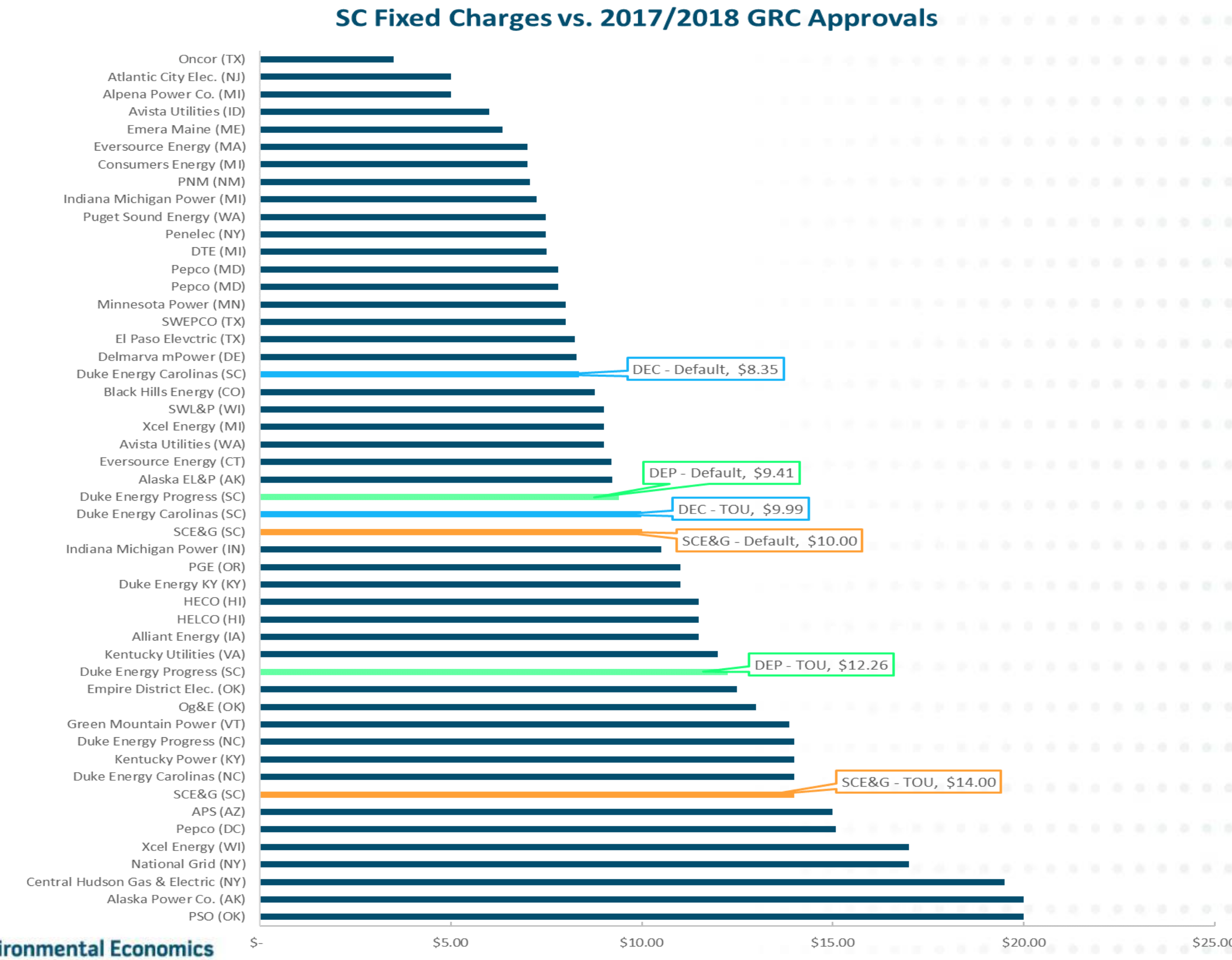
There is also a lot of action with residential customer fixed charges



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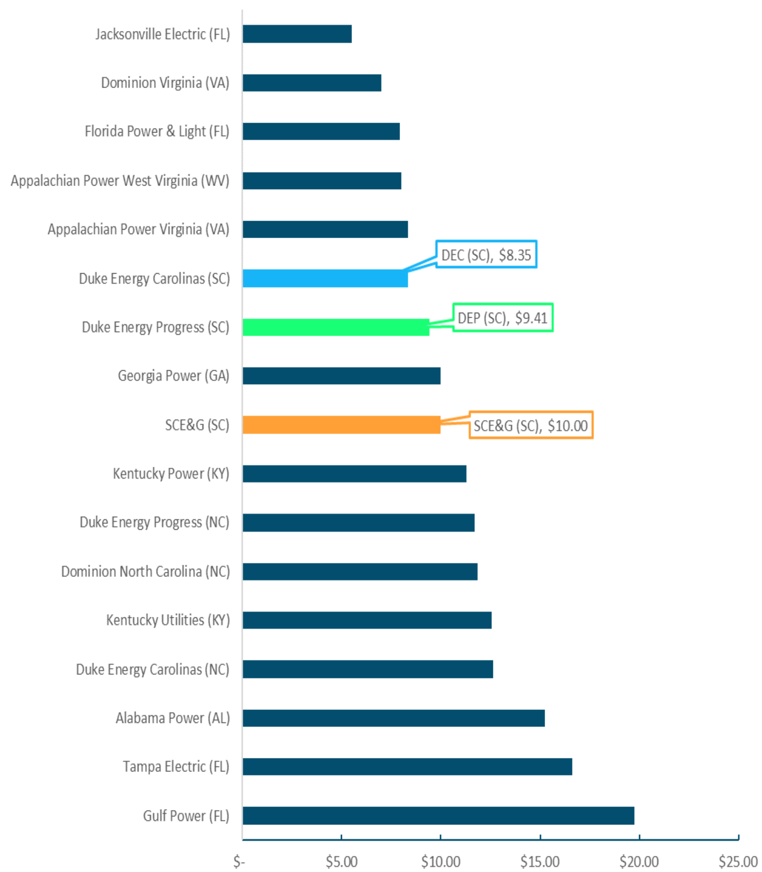
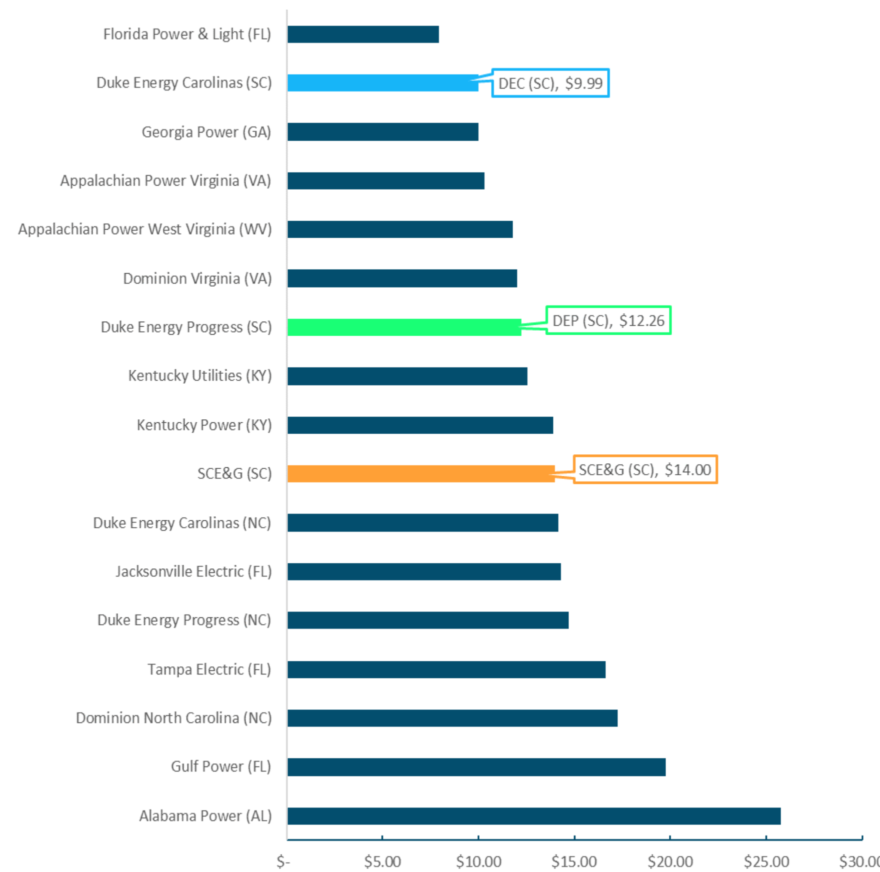
One thing to note is that SC utilities have similar fixed charges

Fixed Charges in the Southeaset: Default Residential Service



Fixed Charges in the Southeast: Residential TOU Service



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Summary of general relevant trends

+ **Full retail NEM is becoming the <u>exception</u> rather than the rule**
  - However, most jurisdictions are taking a <u>gradual</u> approach away from 1:1 retail rate NEM following a glide path to minimize market/customer disruption
+ **Numerous jurisdictions are rethinking their approach to valuing DERs, especially in the context of solar and new emerging technologies like batteries and electric vehicles, with broad variation in approaches and outcomes**
+ **Proposed fixed charge increases are increasingly common; however, these requests are often either scaled back or denied outright**

Case Study: Louisiana

RETAIL (-)

NEM Cap	Compensation	Max. System Size
None: previous cap at 0.5% of retail demand removed in Dec 2016	• *Systems registered prior to the NEM cap*: 1:1 retail credit* • *Systems registered after NEM cap reached*: compensation for excess generation at avoided-cost rate**	• Residential: 25 kW • Commercial/Agricultural: 300 kW

*NEM credits "roll over" month-to-month; if credits remain at time of service/account ending, paid out at avoided cost
**Avoided-cost rate in Louisiana: commodity rate , plus any locational, capacity-related, or environmental benefits

- **Prior to 2016, customers received full retail NEM**
- **Beginning 2016, compensation for excess generation reduced to average-cost rate**
- **Currently a buy all / sell all compensation structure is under consideration**

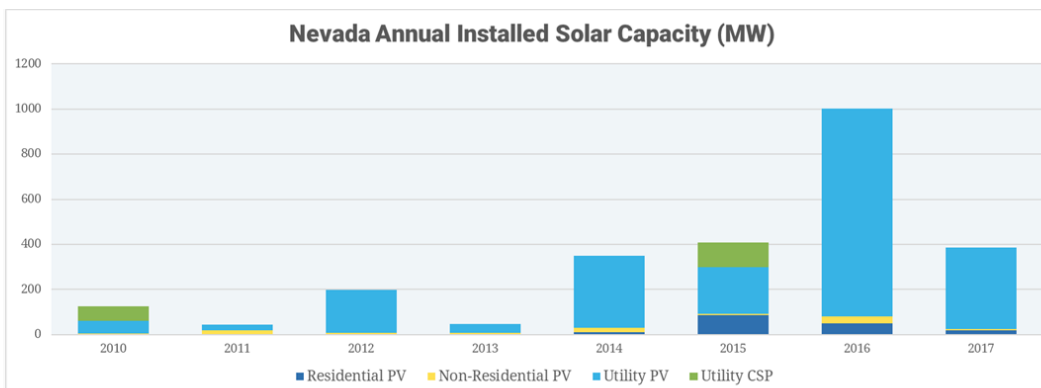
Case Study: Nevada

RETAIL (-)

NEM Cap	Compensation	Max. System Size
None (removed)	95% of retail rate*	1 MW or 100% of customer's annual electricity usage

*NEM credits decline by 7% for each 80 MW of DG PV installed, until reaching 75% of the retail rate

+ **2015 PUC decision ended retail NEM**
+ **2017 legislation restored NEM to near-retail levels**
+ **Highly political and combative environment**



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Case Study: Missouri

RETAIL (-)

NEM Cap	Compensation	Max. System Size
5% of utility's single-hour peak load	Net excess generation compensated at avoided-cost rate*	100 kW

*NEM (avoided-cost) credits expire after 12 months or upon service termination

- **April 2018: PSC staff submitted report in grid modernization proceeding recommending more detailed analysis of DER costs/benefits**
- **June 2018: SB 564 provides $28M in solar rebates beginning 2019**

Case study takeaways

- **Each case represents a compromise by various stakeholders although the balance between stakeholders and how that compromise was achieved can vary substantially**
  - Utility
    - Nevada: near-retail rate compensation for NEM customers after NEM was initially eliminated
    - Missouri: increased funding for solar rebates
  - Solar industry
    - Nevada: haircut to NEM compensation, increasing over time
  - Environmental groups
  - Others?
- ***What compromises can be put on the table as we move forward to Act 236 Version 2.0?***


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NEXT STEPS

There are many compromise options:

Remember as we search for the right compromise we should try to rely on sound data and analytics!

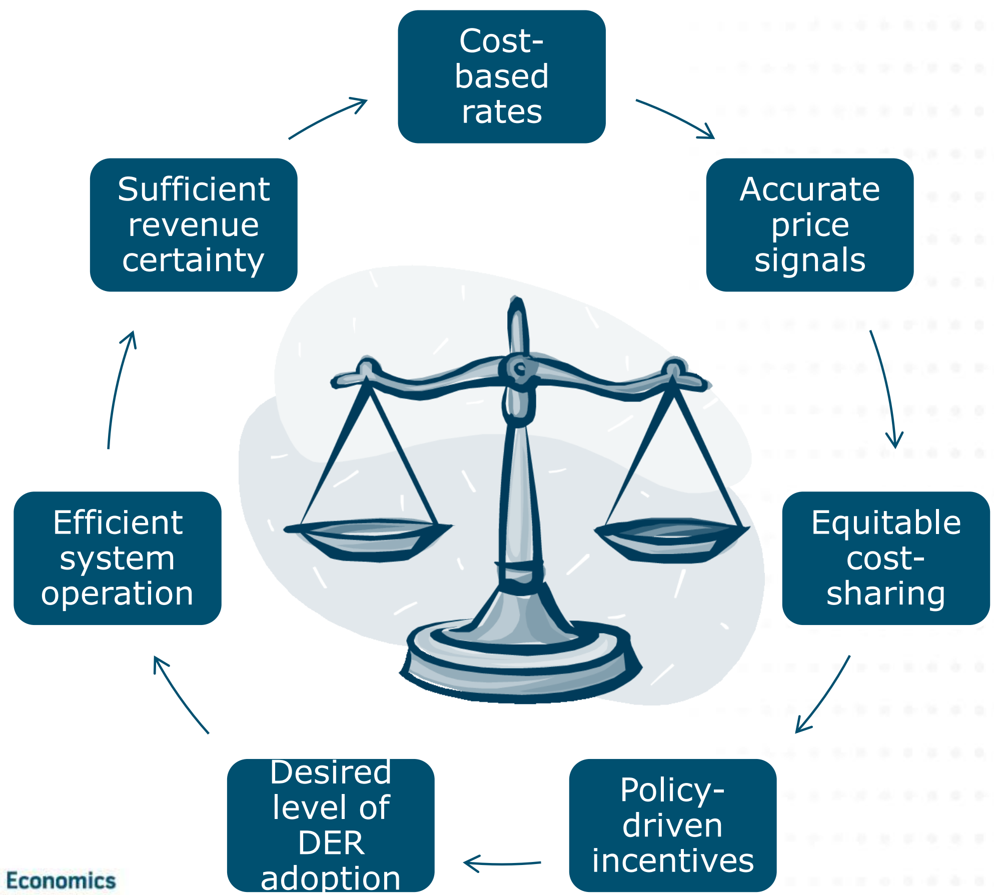
- **Retail (-)**
  - This can include increased fixed charges or minimum bills to better reflect utility cost to serve
- **Value of Solar (+)**
  - This could be compensation directly tied to the NEM formula similar to a QF-style tariff
- **TOU rates to better reflect more dynamic energy costs**
- **"Transition" tariffs with phased energy credits**
  - Retail rates → transition credits → embedded/avoided cost rate

- **Reduction in NEM value**
  - 95% → 90% → 85% → ?
- **Asymmetric compensation**
  - Self-consumption and net export valued differently, e.g. at retail vs. avoided costs
- **Distinct DER/solar adopter customer rate class**
- **Support/protection for low-to-moderate income customers**
  - For example: grants, financing, direct subsidies, community solar, bill protection, cost / revenue shift caps, etc.

Remember where we started?

Are we any closer?

+ ***Goal:*** **Retail rates and DER compensation mechanisms that accurately reflect South Carolina values**



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THANK YOU!

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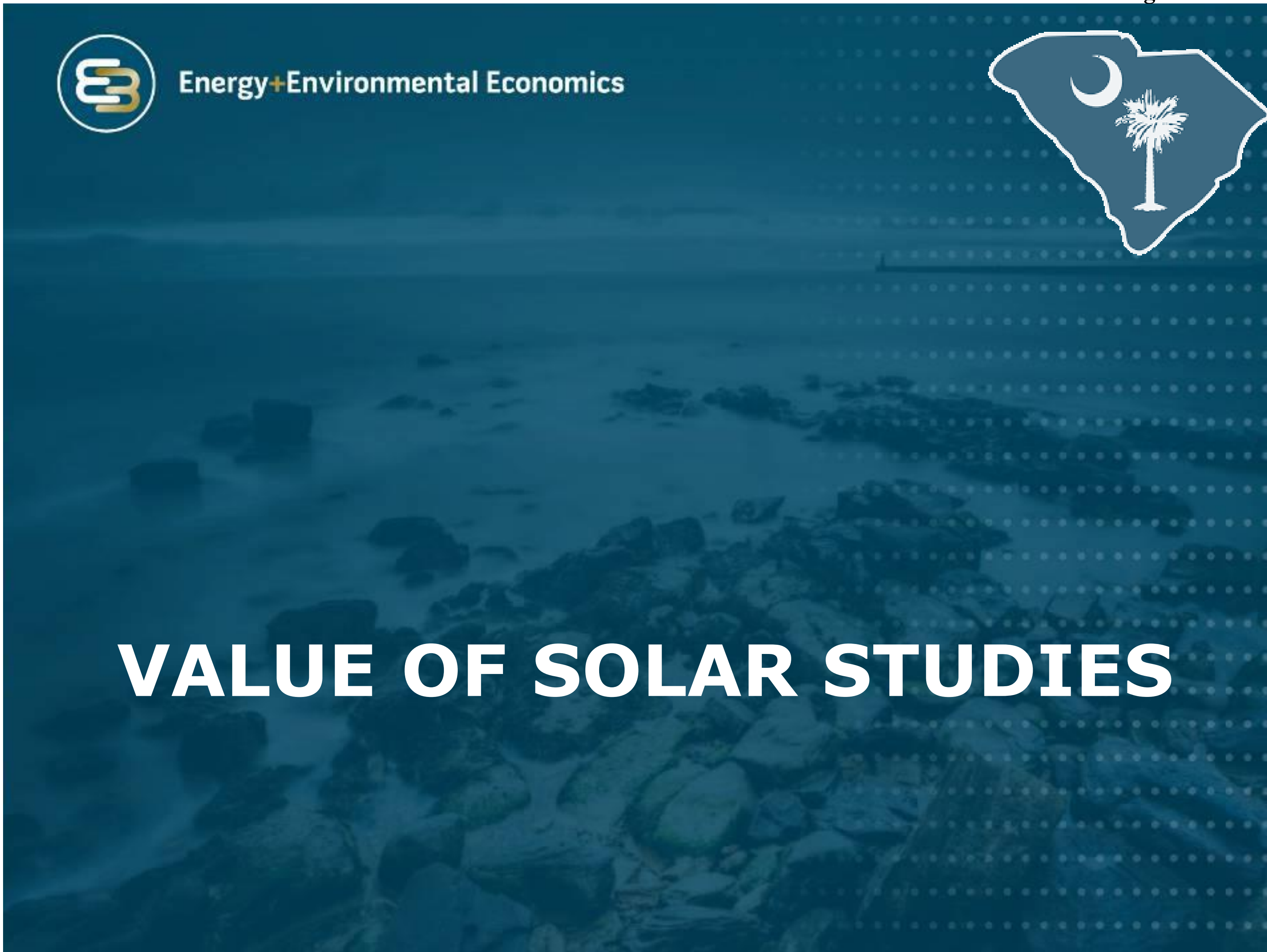
APPENDIX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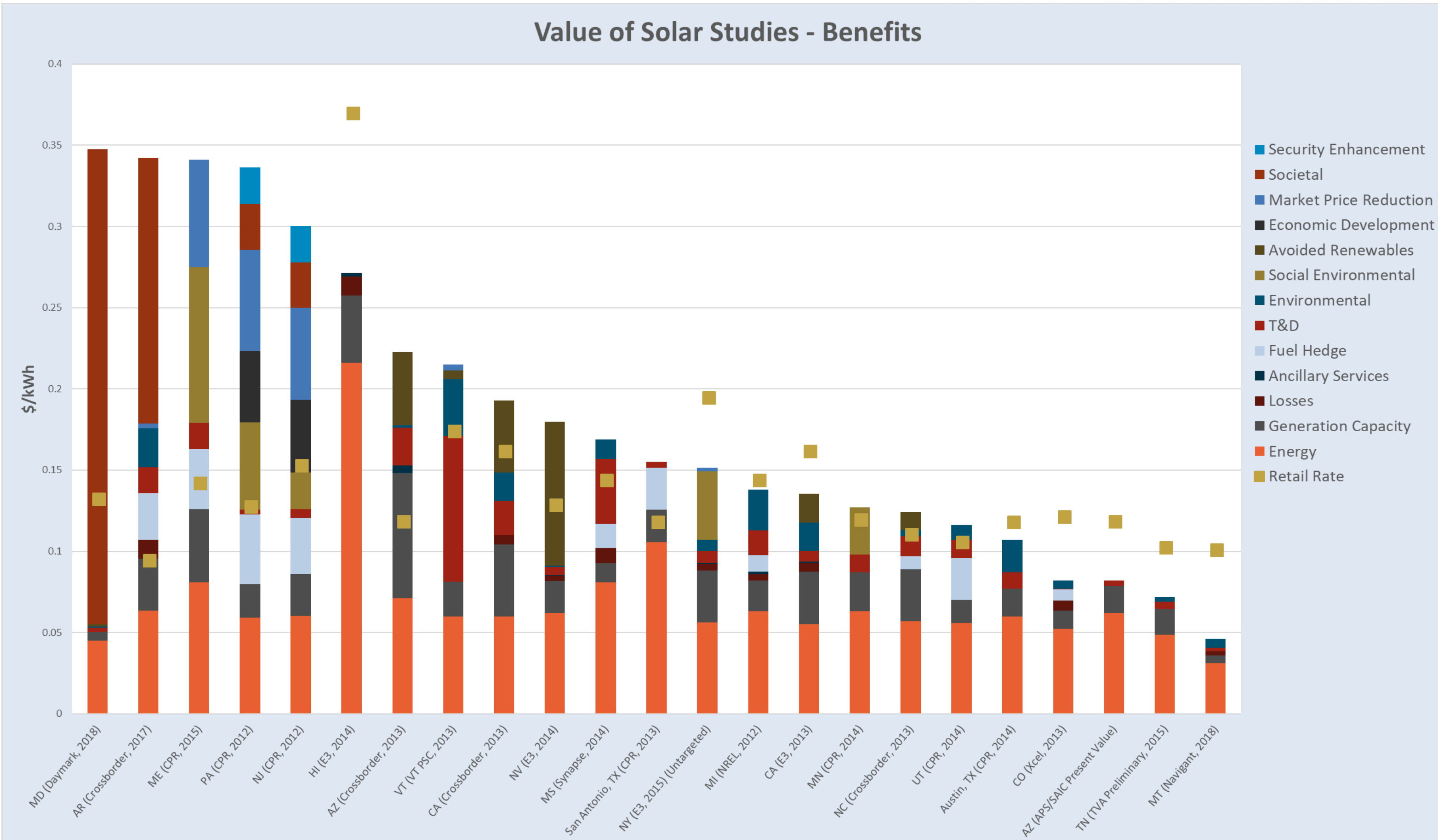
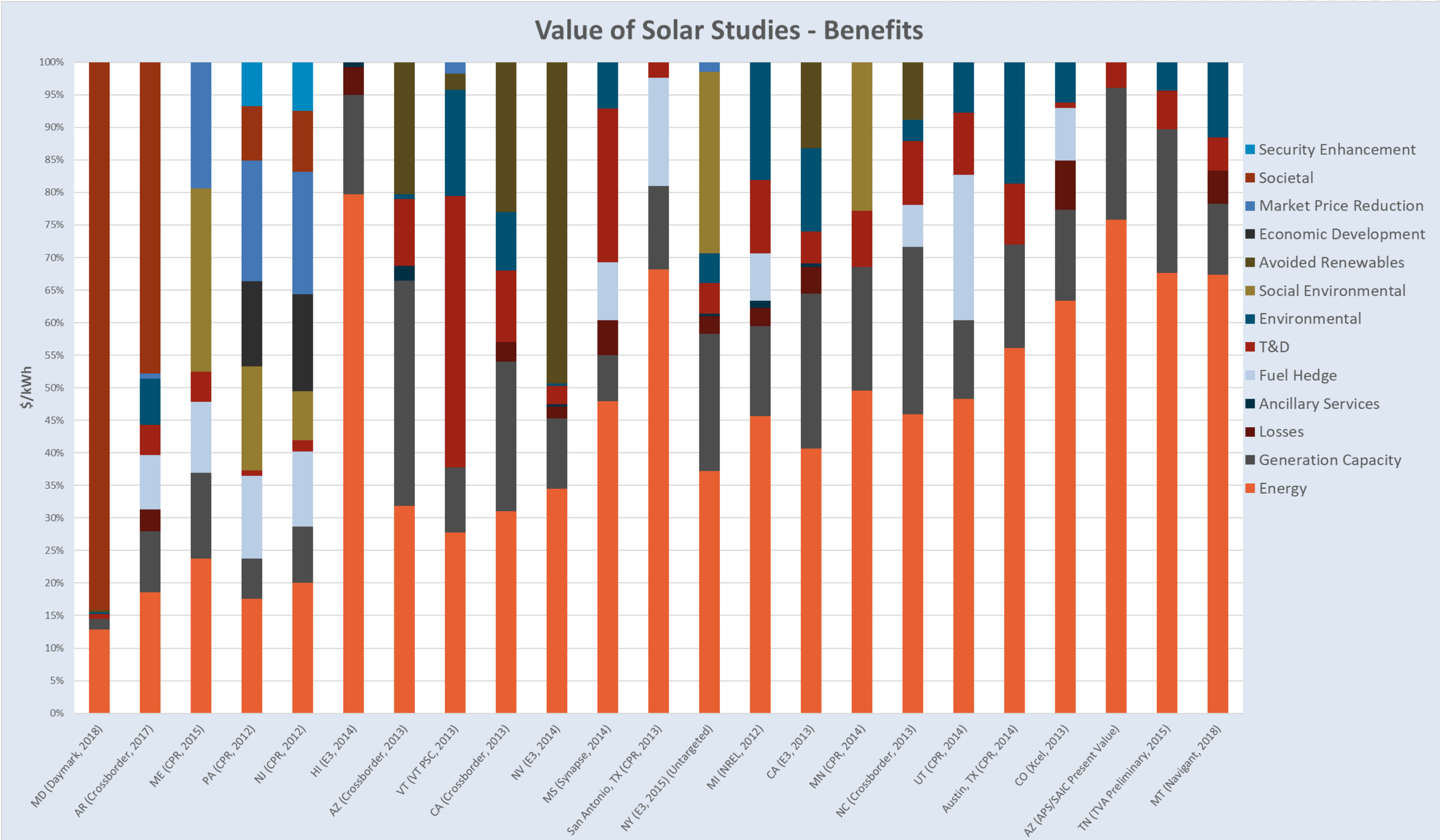
VALUE OF SOLAR STUDIES

VoS studies range broadly in their benefits assessments (1)



VoS studies range broadly in their benefits assessments (2)



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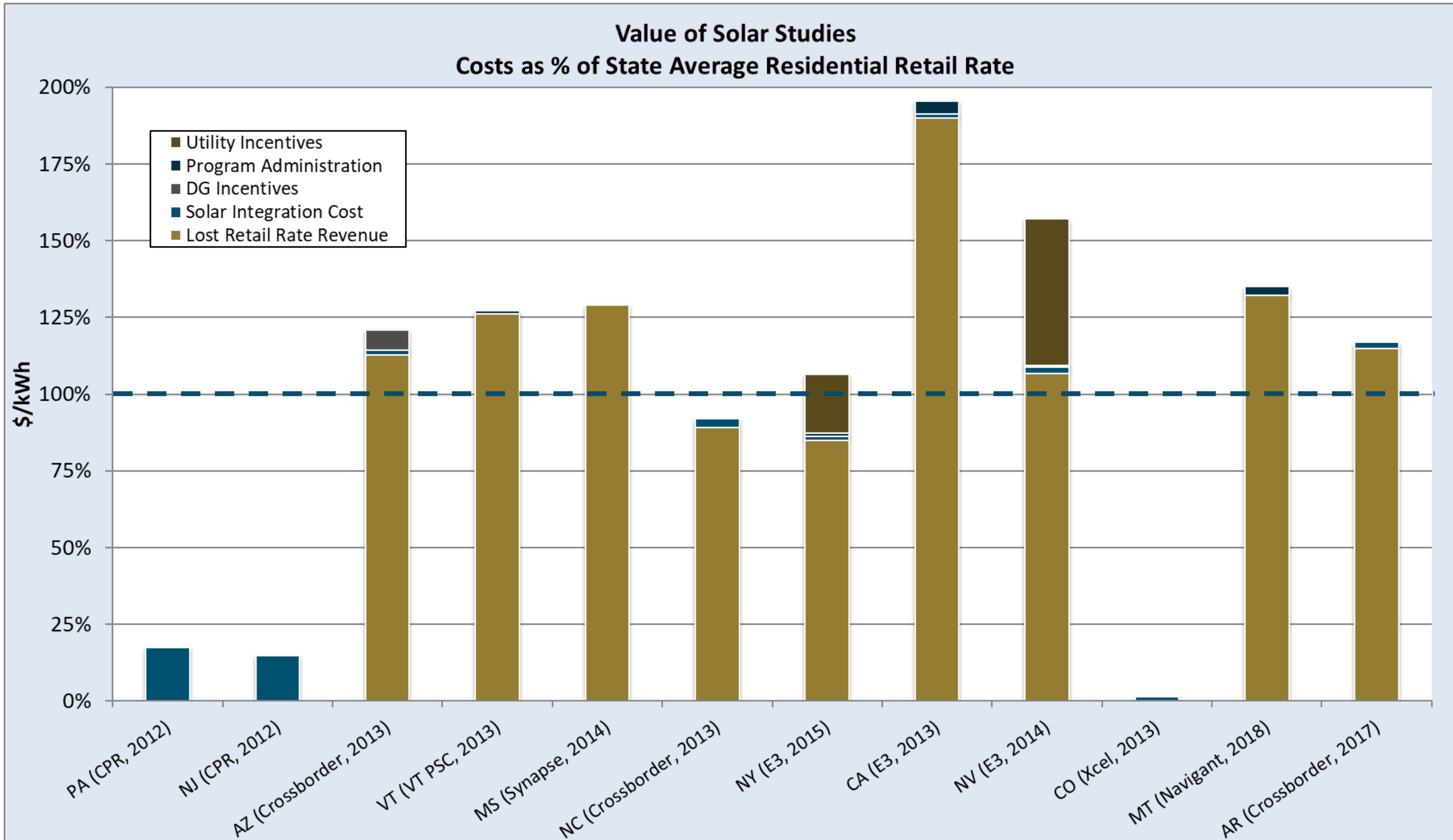
Cost assessments also range broadly (1)



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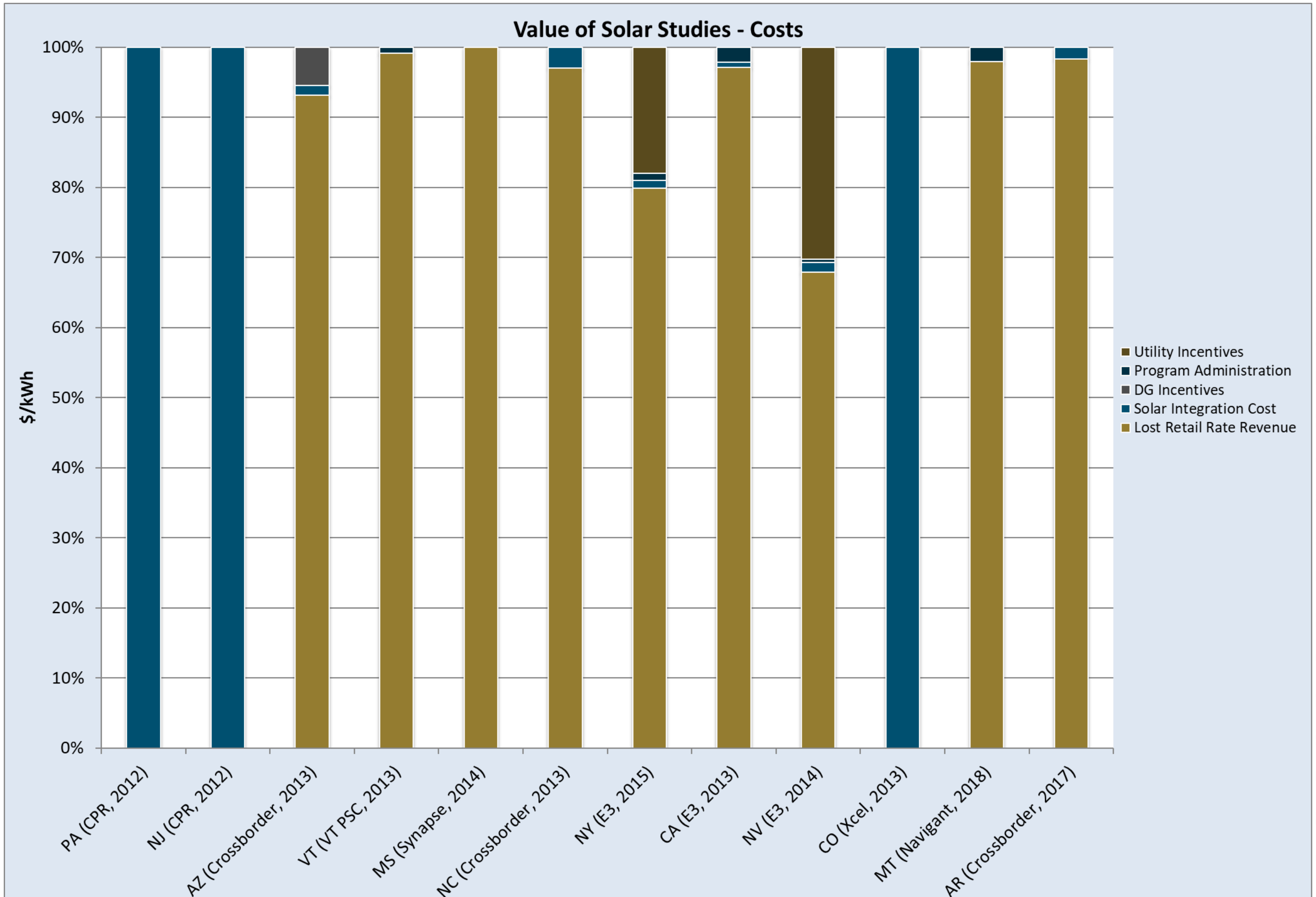
Cost assessments also range broadly (2)

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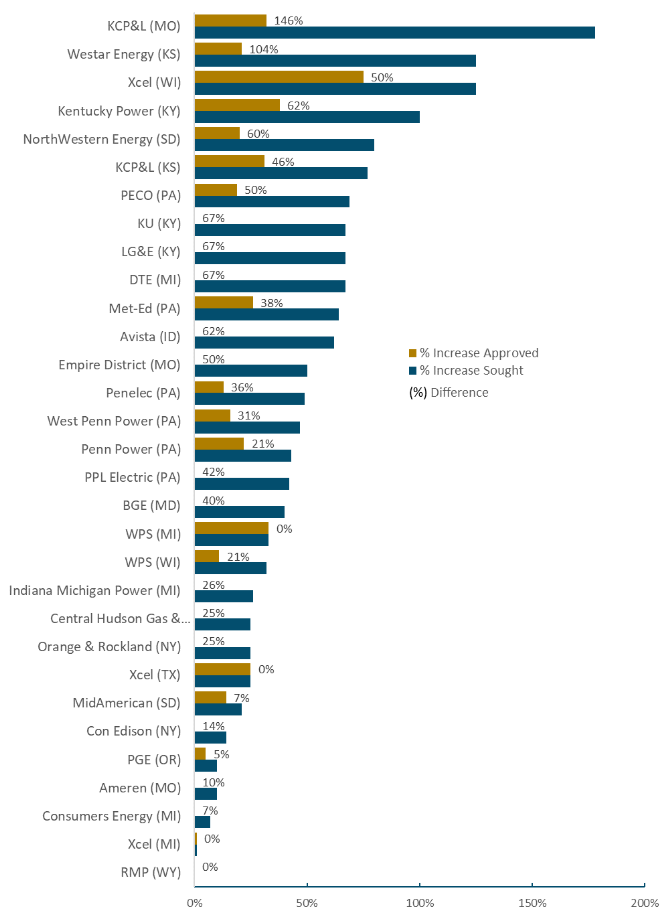
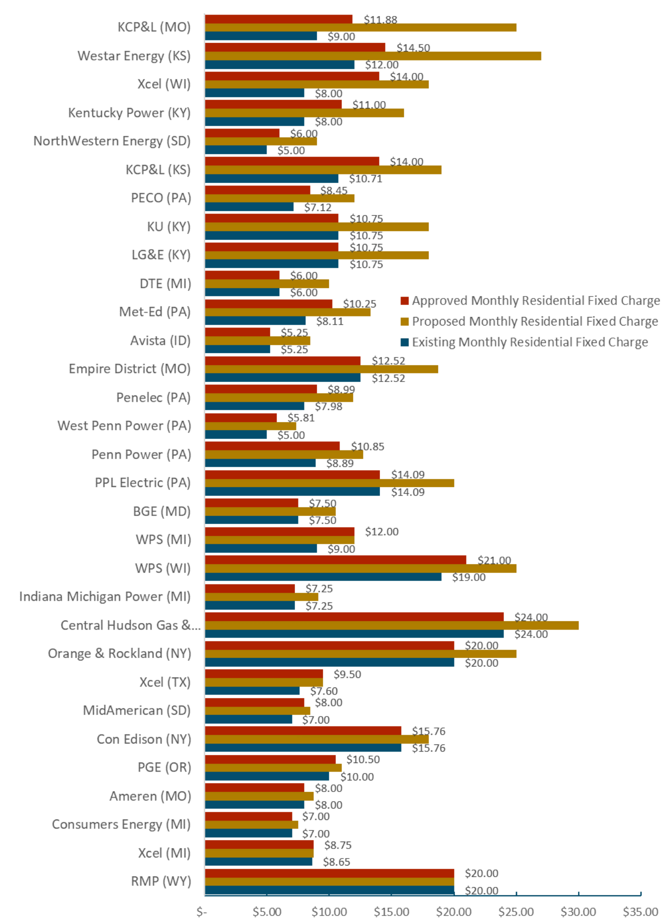
FIXED CHARGES

2015 Residential Fixed Charge Increases





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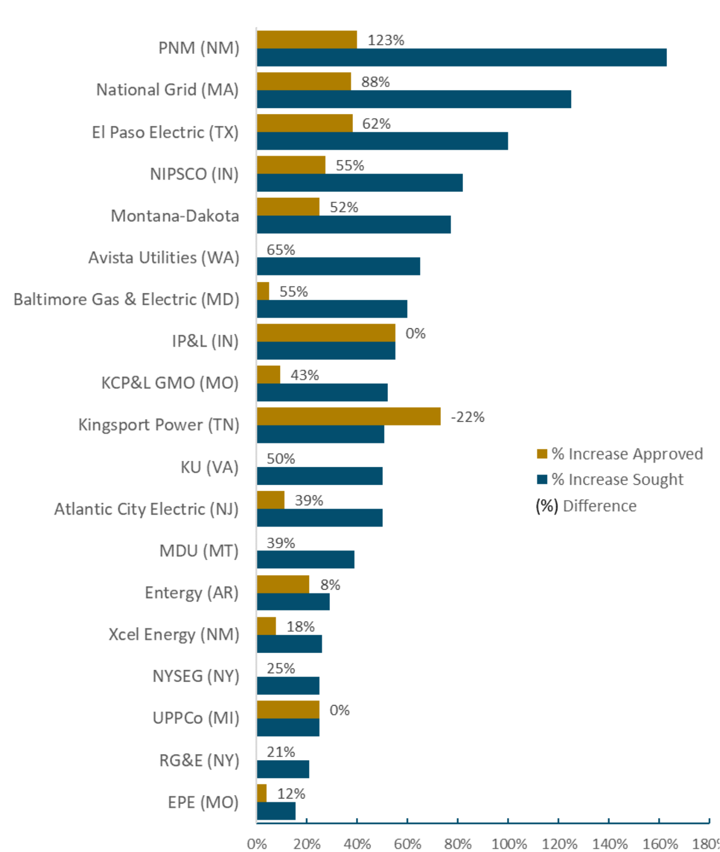
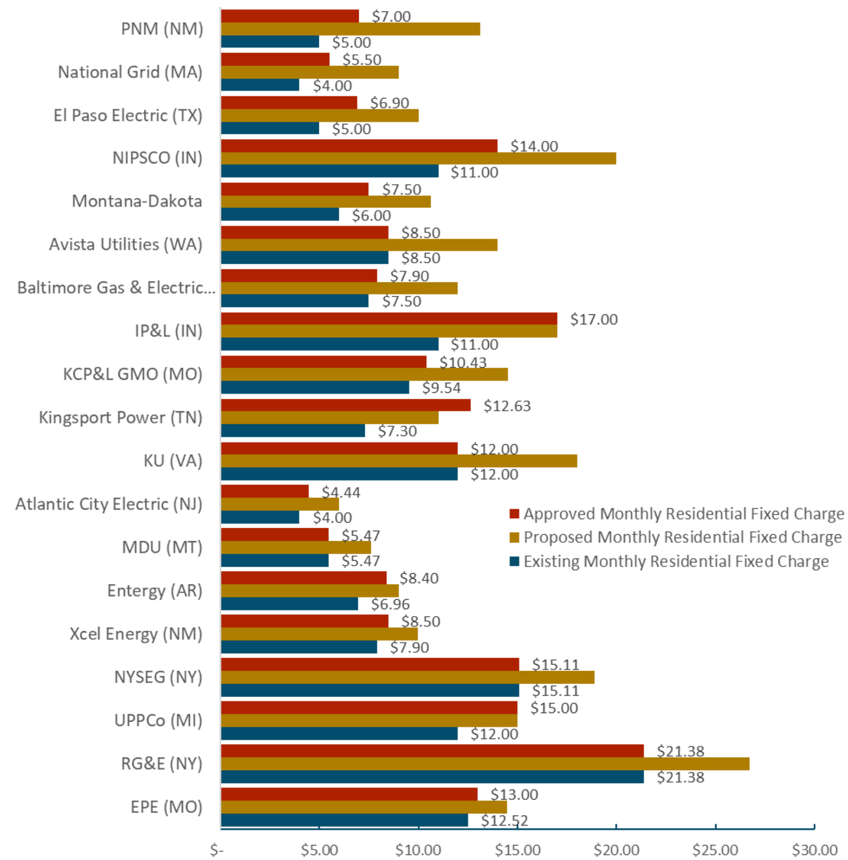
2016 Residential Fixed Charge Increases





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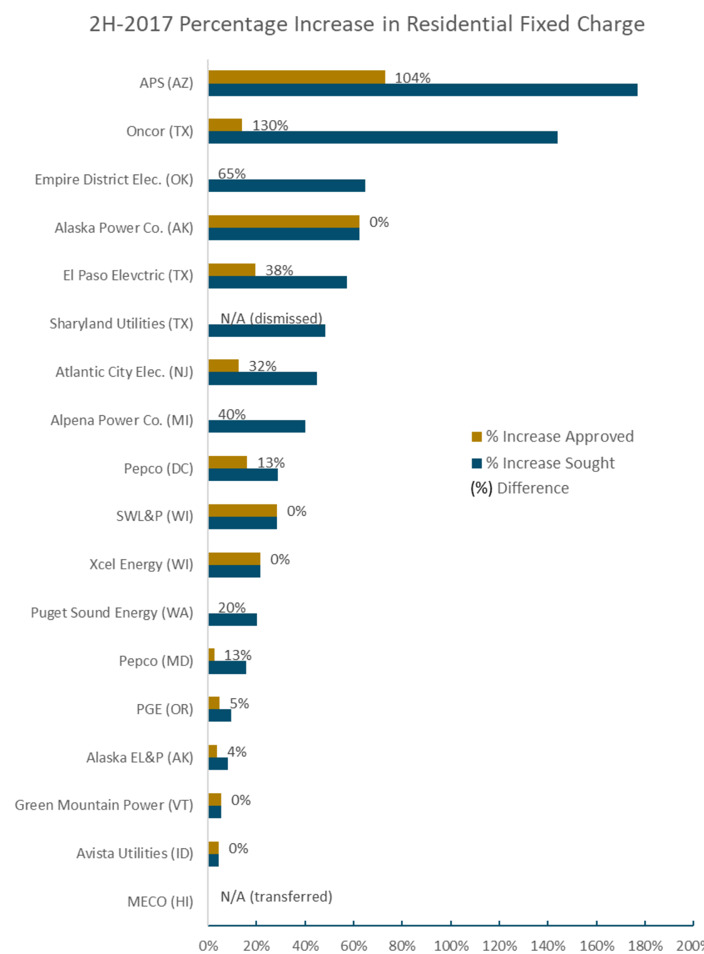
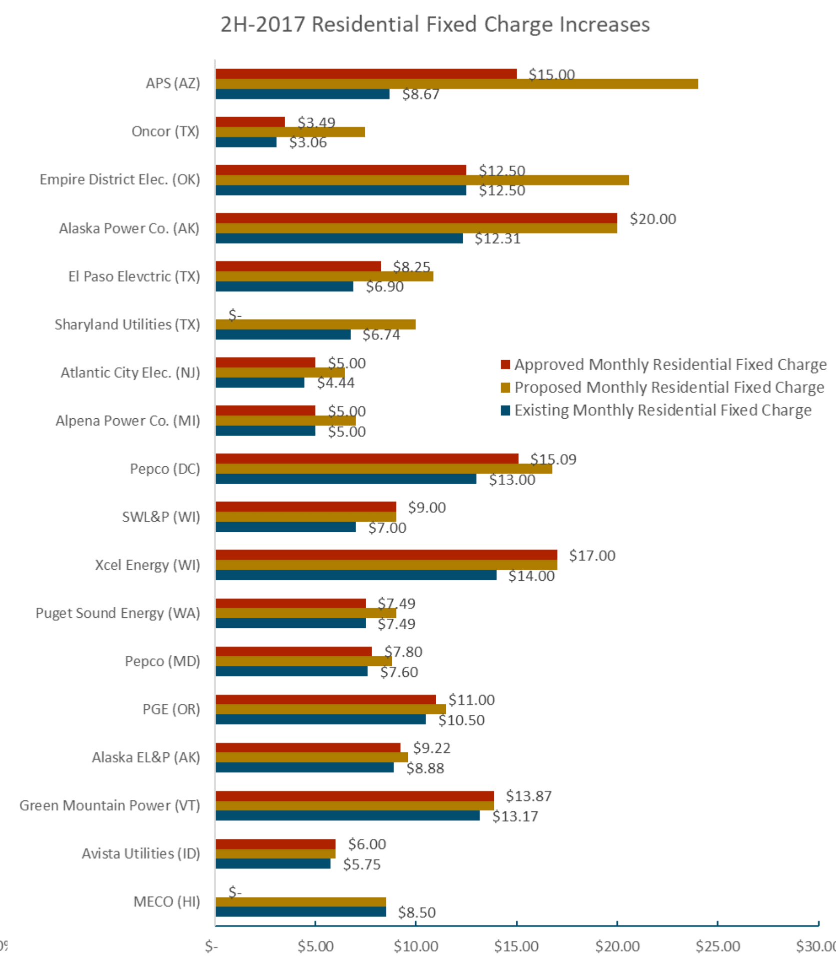
2015/16 Trends

- Percentage increases approved in 2015 range from 1% (25¢) to 75% ($6)
- Percentage increases approved in 2016 range from 4% (48¢) to 73% ($5.33)
- In the case of the 75% increase, the increase approved exceeded proposed increase
- Increase cut across several jurisdictions, except in New York

2H-2017 Residential Fixed Charge Increase





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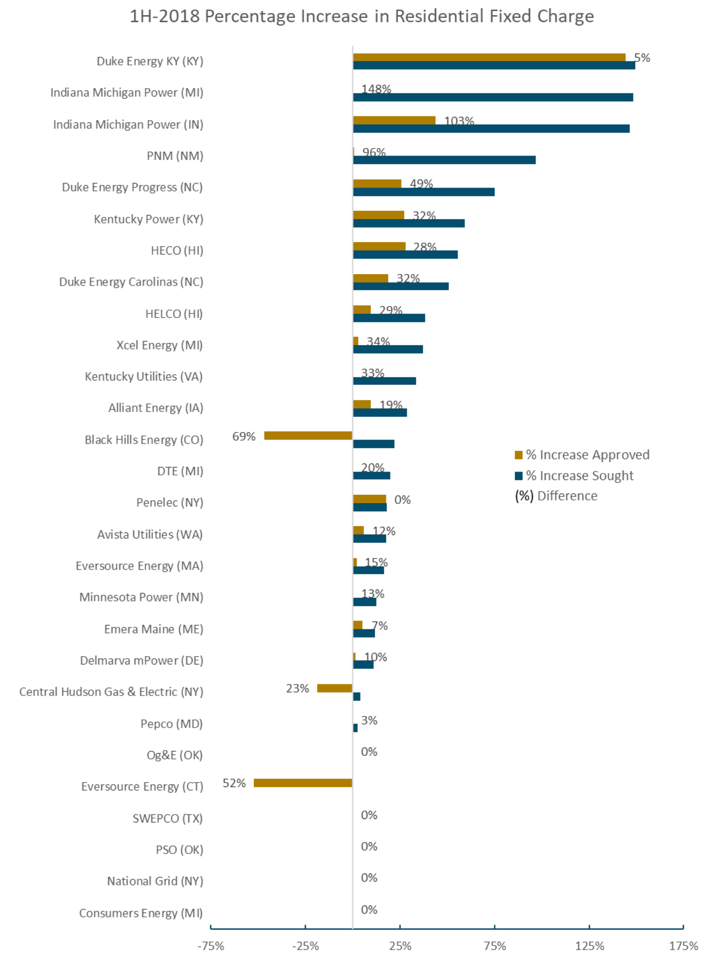
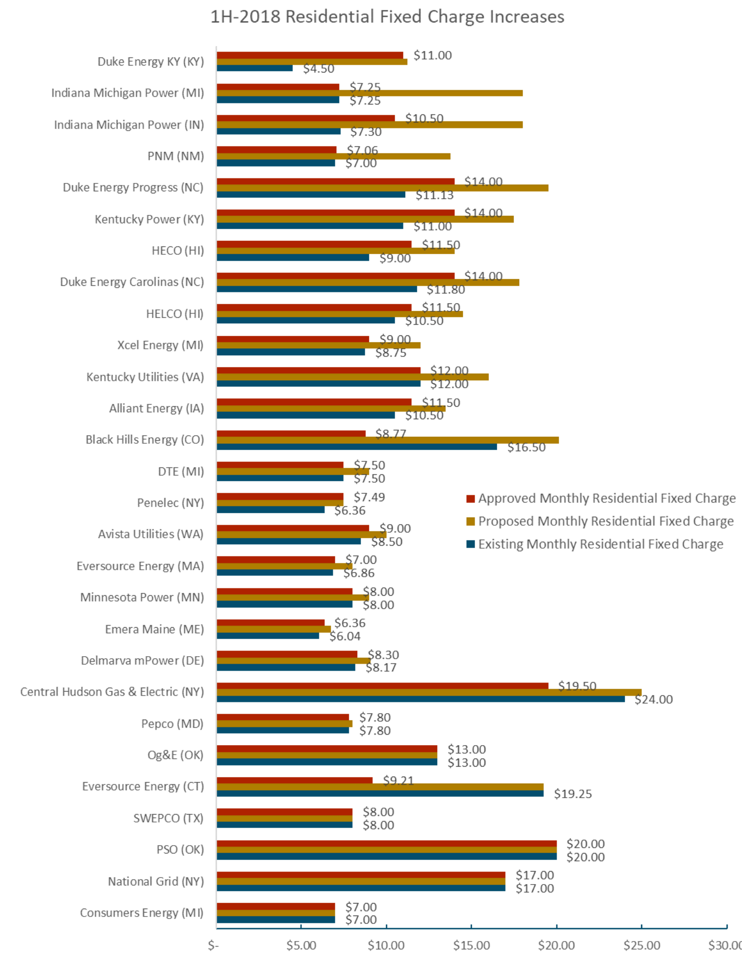
1H-2018 Residential Fixed Charge Increase





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2017/18 Trends

- **Percentage increases approved in 2017 range from 3% (20¢) to 73% ($6)**
- **Percentage increases approved in 2018 range from -52% (-$10) to 144% ($6.50)**
- **Several significant decreases:**
  - Black Hills Energy: 47% ($8) *decrease* [vs. proposed increase of 22% ($3.60)]
  - Eversource Energy CT: 52% ($10) *decrease* [vs. no proposed increase]

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ADDITIONAL CASE STUDY: COLORADO STAKEHOLDER AGREEMENT

Colorado settlement showed successful collaboration with diverse stakeholders

- **2016 settlement covering rate design & NEM, community solar & green tariffs, and IOU renewable programs capacities**
  - Consolidated issues across several distinct PSC proceedings to cover "full spectrum"
- **Rate Design & NEM**
  - Xcel initially proposed "grid-use" fee in GRC to cover fixed distribution costs (paired with lower volumetric rate / lower NEM credit); pushback from solar & consumer groups
  - Settlement instead established a voluntary TOU trial for residential customers & a time differentiated rate (TDR) demand charge pilot for residential and commercial customers
    - Expectation of default TOU rates in future (~2020)
  - Key compromise: agreement of solar bloc not to oppose separate decoupling proceeding
- **Community Solar, Green Tariffs & Renewable Program Capacities**
  - 50 MW utility-owned solar installation proposed, sold via retail subscriptions to green rider
  - Developer concern over competition from Xcel; IOU perceived as having unfair advantage
  - Added 225 MW of solar to green rider program, and 105 MW of community solar
  - Key compromise: amendment prohibiting sale of subscriptions to residential customers (the main market for CS developers)

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Colorado Takeaways

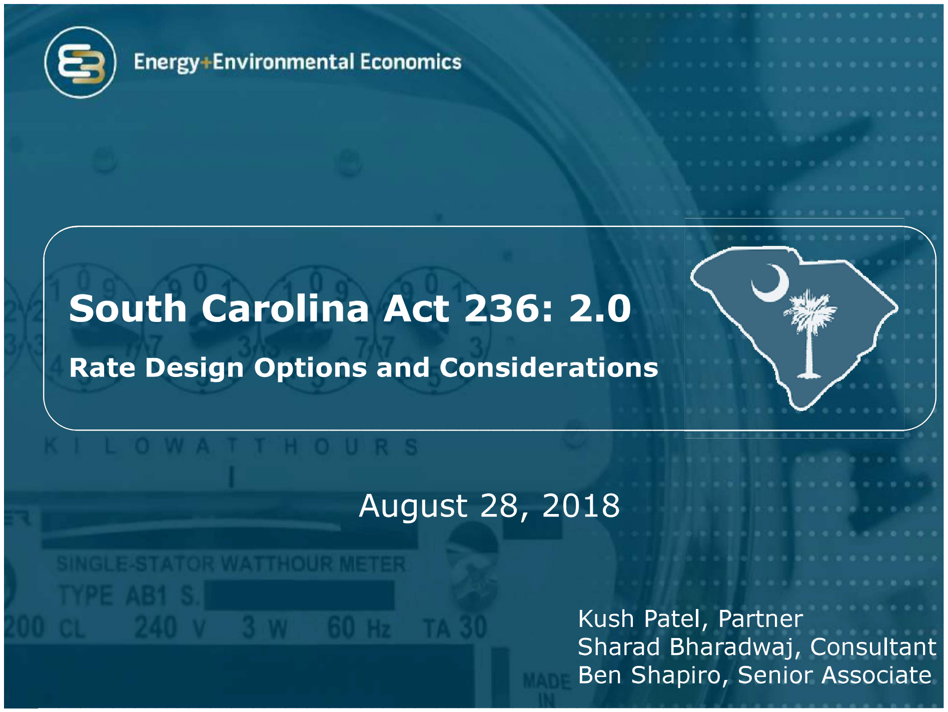
+ What made the Colorado settlement successful?

- **Comprehensive** – considered multiple issues across several proceedings
- **Compromise** – each group committed to several concessions in order to finalize deal
- **Communication & collaboration** – established ongoing quarterly stakeholder meetings

Sources & Useful Links

- NCCETC 50 States of Solar Q1 2018 Quarterly Report - Executive Summary
- NCCETC 50 States of Solar Q4 2017 Quarterly Report & 2017 Annual Review – Executive Summary
- SRNL South Carolina Solar Development - Tracking the Effects of Act 236 (2014- 2017)
- SC State Energy Plan
- 2015 E3 Cost Shift Analysis
- 2017 Distributed Energy Resource and Net Metering Implementation – ORS Report
- 2016 Distributed Energy Resource and Net Metering Implementation – ORS Report

9.8.2 RATE DESIGN OPTIONS AND CONSIDERATIONS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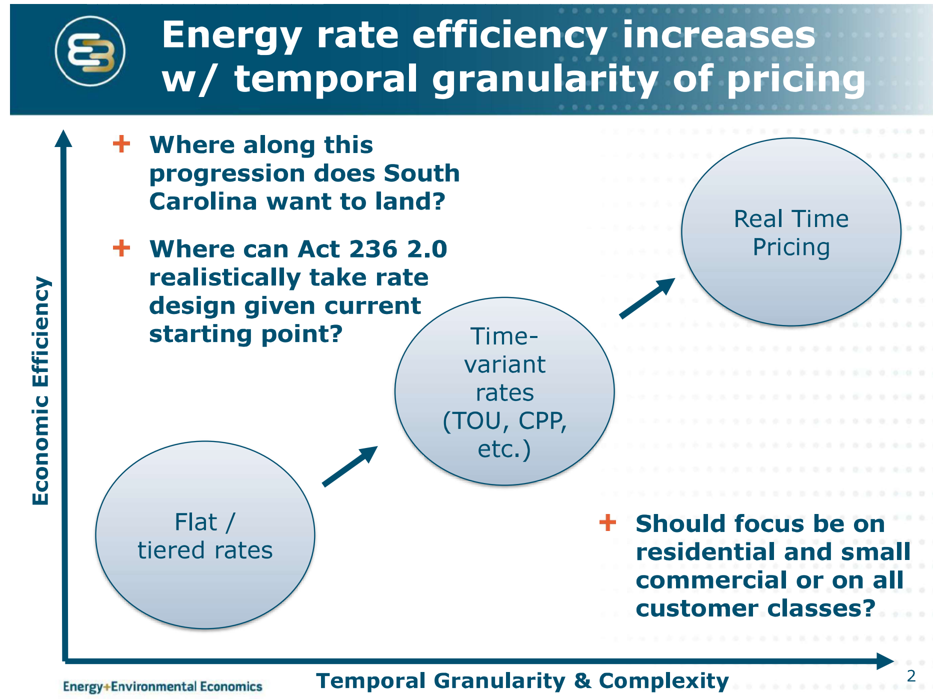
South Carolina Act 236: 2.0
Rate Design Options and Considerations
August 28, 2018
Kush Patel, Partner
Sharad Bharadwaj, Consultant
Ben Shapiro, Senior Associate


Energy rate efficiency increases w/ temporal granularity of pricing
+ Where along this progression does South Carolina want to land?
+ Where can Act 236 2.0 realistically take rate design given current starting point?
+ Should focus be on residential and small commercial or on all customer classes?
Economic Efficiency
Flat / tiered rates
Time-variant rates (TOU, CPP, etc.)
Real Time Pricing
Temporal Granularity & Complexity
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Spectrum of Smaller Customer Rate Designs (illustrative)

Increasing Complexity & Economic Efficiency

Gradual Shift with Existing Structure "The Quick Fix"	*Bigger Shift with Existing Structure* "Middle-ground"	*Large Structural Shift* "The Economist"
Increased customer charge	Size-differentiated **customer** charge	Customer charge
		Demand charge
Decreased volumetric rate	Either existing volumetric energy rate, or mandatory TOU	Time-varying energy rate

Issues to address

+ **How to best collect embedded costs?**
  - [Customer charge] vs. [size-differentiated *customer* charge] vs. [customer charge + *demand* charge]
  - If size-differentiated customer charge or more traditional demand charge, how to calculate?
+ **How granular/accurate should a time-variant energy rate be?**
  - Seasonal TOU? Critical Peak Pricing (CPP)? Real Time Pricing (RTP)?
+ **In absence of a more "economic" 3-part rate, what proportion of embedded costs should be collected via fixed vs. variable charges?**
+ **Should DER customers be placed in a separate class due to their lack of homogeneity with the rest of the class?**
+ **Will customers be able to understand the proposed changes to their rates?**
+ **What is the best way to pair the proposed rate with support for LMI customers?**

Need for stakeholder compromise may preclude most efficient rates

- **Maintaining 1:1 volumetric NEM "kicks the can down the road" which may be OK for market stability and transition**
- **A 3-part, more economically efficient rate structure takes the long-term view on rate design, but may not be practically implementable at this point**
- **One potential compromise is making the optional TOUs (current or revised) the default rate for all DER customers**
  - Lower energy rates and higher fixed charges would be more reflective of true system costs, without introducing unnecessary complexity
  - TOU rate can remain optional for other non-DER customers, further reducing complexity of rate design

One version of a SC compromise: Duke Residential TOU

- **Existing Duke TOU rate has relatively low energy charge, recovering embedded costs through on-peak demand charges and a higher BFC**
  - Current SCE&G TOU rate looks less economic as it relies more on energy charges for cost recovery
- **Making Duke's TOU structure (or a similar variant) mandatory for all DER customers may be the best middle-of-the-road option that still moves SC along the path to more economically-efficient rates**
- **DER compensation could take several forms**
  - 1:1 *within periods* (current approach); negotiated settlement (Retail (-)); Avoided Cost (+); etc.

Residential TOU Rates	SCE&G	DEC	DEP
TOU Peak Hours	S: 2-7pm W: 7am-12pm	S: 1-7pm W: 7am-12pm	S: 10am-9pm W: 6am-1pm, 4-9pm
Basic Facilities Charge ($/mo)	$ 14.00	$ 9.93	$ 11.91
Energy On-peak [Summer] ($/kWh)	$ 0.316	$ 0.066	$ 0.085
Energy Off-peak [Summer] ($/kWh)	$ 0.105	$ 0.054	$ 0.070
Energy On-peak [Winter] ($/kWh)	$ 0.284	$ 0.066	$ 0.085
Energy Off-peak [Winter] ($/kWh)	$ 0.105	$ 0.054	$ 0.070
On-peak demand charge [S] ($/kW)	N/A	$ 8.15	$ 5.38
On-peak demand charge [W] ($/kW)	N/A	$ 4.00	$ 4.14

Other options

+ **Comprehensive reform of rate design**
  - Focus on economic efficiency and cost causation
  - Single rate treats all distributed generation resources and customer load reductions equivalently, valued at true system cost
+ **Negotiated settlement**
  - Retail (-), i.e., haircut to retail rates for DER generation
+ **Avoided cost, plus adders**
  - Value of DER (+), i.e., individual value components, plus any negotiated incentives for DG / DER

Next Steps (E3)

Updated Cost Shift Analysis
- Currently collecting necessary data to refresh model and address additional stakeholder questions

Rate Design Analysis
- What effect will different proposed rate designs have on the economics of different DERs? (focus on BTM PV; w/ other DERs assessed as well)

Reporting of Results
- Final written report will incorporate results of both analytical exercises, along with recap of national trends and potential paths forward for SC

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APPENDIX A: ILLUSTRATIVE RATE DESIGN OPTIONS

Potential "Ideal" Rate Structures (1)

+ **Key issues addressed:** Recommend that DER in separate class or a low-income rate be established given that in SC highest usage residential customers tend to be poorest

Gradual shift from today		Bigger shift from today		Large structural shift from today	
2-part	*Proposal*	*2-part*	*Proposal*	*3-part*	*Proposal*
Customer Charge	Current \$10 → \$15-\$30 with some demand related embedded costs	Customer Charge	Minimum of \$10, with 3 tiers of sizes (Avg. of 5 monthly NCP kW demand or average of max 3-months kWh usage)	Customer Charge	Current \$10 → \$15-\$20 for only customer related charges
				Demand Charge	Avg. of 5 monthly NCP kW demand (collects embedded demand related costs)
Energy Charge	Seasonal 2-period (peak/off-peak) TOU for energy/capacity costs + some demand related embedded costs	Energy Charge	Seasonal 3-period TOU for energy/capacity costs + some demand related embedded costs	Energy Charge	Seasonal 3-period TOU for energy/capacity costs

Potential "Ideal" Rate Structures (2)

+ **Key issues addressed:** Separate prosumer class necessary to effectively address NEM cost-shift; *intentional* cost-shifts reasonable to support BTM policy goals; important to factor in standby and grid integration charges (not currently accounted for)

Gradual shift from today		Bigger shift from today		Large structural shift from today	
2-part	*Proposal*	*2-part*	*Proposal*	*3-part*	*Proposal*
Customer Charge	Grid-usage fee, based on customer size (embedding demand w/out distinct demand charge)	Customer Charge	Grid-usage fee, based on customer size (embedding demand w/out distinct demand charge)	Customer Charge	Current $10 → $15-$20 for only customer related charges
				Demand Charge	Daily demand charges
Energy Charge	TOU w/ high evening peak charge (energy charges overall set lower than current levels)	Energy Charge	Standard tariff rate for net usage; net exports credited at wholesale + avoided cap. cost (ideally netting on hourly time-scale)	Energy Charge	Lower energy rate to reflect only marginal energy costs & losses

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Potential "Ideal" Rate Structures (3)

+ **Key issues addressed:** NEM should not be thought of in isolation; create separate DER customer class; utilities should be buying a lot of utility-scale solar

BTM compensated at full avoided cost; distinct DER class	
3-part	*Proposal*
Customer Charge	Current $10 → $20-$30?
Demand Charge	Rolling average daily demand charges
Energy Charge	Lower than current rates, representing marginal energy + losses

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APPENDIX B: EXISTING RATES IN SOUTH CAROLINA

Rate Summary

+ **Residential**
  - Similar default structure across all IOUs (flat rate, no demand charge, some seasonally-based energy rates)
  - TOU rates: SCE&G based on high energy charges (no demand charge); both Duke utilities employ seasonally-differentiated demand charges to recoup fixed costs
+ **Commercial**
  - Variations on declining block energy rates, w/ demand charges*
+ **Industrial****
  - SCE&G: large fixed charge, low energy rate, moderate demand charge
  - DEC: small fixed charge, higher energy rate

*DEP small commercial tariff does not include a demand charge; DEC commercial tariffs use kWh/kW billing demand blocks, in addition to a standard demand charge

** DEP does not appear to offer an industrial tariff

Residential

Residential						
	SCE&G		DEC		DEP	
	Default	TOU	Default	TOU	Default	TOU
TOU Peak Hours	N/A	S: 2-7pm W: 7am-12pm	N/A	S: 1-7pm W: 7am-12pm	N/A	S: 10am-9pm W: 6am-1pm, 4-9pr
Basic Facilities Charge ($/mo)	10	14	8.29	9.93	9.06	11.91
Energy (Summer) ($/kWh)	.137 (.15 above 800 kWh)	N/A	0.099 (.105 above 1,000 kWh)	N/A	0.116	N/A
Energy (Winter) ($/kWh)	.137 (.13 above 800 kWh)				0.116 (0.106 above 800 kWh)	
Energy On-peak (S) ($/kWh)	N/A	0.316	N/A	0.066	N/A	0.085
Energy Off-peak (S) ($/kWh)		0.105		0.054		0.070
Energy On-peak (W) ($/kWh)		0.284		0.066		0.085
Energy Off-peak (W) ($/kWh)		0.105		0.054		0.070
On-peak demand charge (S) ($/kW)	N/A	N/A	N/A	8.15	N/A	5.38
On-peak demand charge (W) ($/kW)				4.00		4.14

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Small Commercial

Small Commercial					
	SCE&G		DEC	DEP	
	Default	TOU	Default	Default	TOU
TOU Peak Hours	N/A	S: 2-7pm W: 7am-12pm	N/A	N/A	S: 10am-10pm W: 6am-1pm, 4-9pm
Basic Facilities Charge ($/mo)	22.75	26.4	10.52	9.91	23.17
Energy (Summer) ($/kWh)	0.112 (0.120 above 3,000 kWh)	On-peak: 0.24625 Off-peak: 0.09922 (0.10464 over 1,000 kWh)	1st 125 kWh/kW billing demand: 0.118 for 1st 3,000 kWh 0.059 for next 6,000 kWh 0.052 for all over 9,000 kWh Next 275 kWh/kW billing demand: 0.06 for 1st 3,000 kWh 0.059 for next 6,000 kWh 0.051 for all over 9,000 kWh All over 400 kWh/kW billing demand: 0.044	1st 2,000 kWh: 0.123 Over 2,000 kWh: 0.088	On-peak: 0.06672 Off-peak: 0.05287
Energy (Winter) ($/kWh)	0.112 (0.105 above 3,000 kWh)	On-peak: 0.1877 Off-peak: 0.09922 (0.10464 over 1,000 kWh)			
Demand charge ($/KVA or kW)	3.44/kVA above 250 KVA in Summer	N/A	4.00/kW above 30 kW	N/A	On-peak: S: 11.55; W: 9.02 Off-peak: 2.95

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Large Commercial

Large Commercial					
	SCE&G		DEC	DEP	
	Default	TOU	Default	Default	TOU
TOU Peak Hours	N/A	Jun-Sep: 1-9pm May & Oct: 1-9pm Nov-Apr: 6am-12pm & 5-9pm	N/A	N/A	S: 10am-10pm W: 6am-1pm & 4-9pm
Basic Facilities Charge ($/mo)	210	225	17.16	98	98
Energy ($/kWh)	Up to 75,000 kWh: 0.056 Above 75,000 kWh: 0.051	On-peak: S: 0.0976 W: 0.0672 Off-peak: 0.04965	1st 125 kWh/kW billing demand: 0.127 for 1st 3,000 kWh 0.065 for next 87,000 kWh 0.054 for all over 90,000 kWh Next 275 kWh/kW billing demand: 0.066 for 1st 3,000 kWh 0.065 for next 87,000 kWh 0.057 for all over 90,000 kWh All over 400 kWh/kW billing demand: 0.050	0.053	On-peak: 0.05316 Off-peak: 0.01816
Demand charge ($/KVA or kW)	16.82/KVA	On-peak: S: 24.5 W: 16.55 Off-peak: 5.25	4.11/kW above 30 kW	1st 5,000 kW of billing demand: 12.8/kW Next 5,000 kW of billing demand: 11.8/kW All billing demand over 10,000 kW: 10.8/kW	On-peak (1st 5,000 kW) - S: 19.60, W: 14.57 On-peak (next 5,000 kW) - S: 18.60, W: 13.57 On-peak (over 10,000 kW) - S: 17.60, W: 12.57 Off-peak: 1.25

Industrial

Industrial		
	SCE&G	DEC
Basic Facilities Charge ($/mo)	2,050	22.97
Energy charge ($/kWh)	0.049	1st 125 kWh/kW billing demand: 0.118 for 1st 3,000 kWh 0.060 for next 87,000 kWh 0.044 for all over 90,000 kWh Next 275 kWh/kW billing demand: 0.60 for 1st 3,000 kWh 0.055 for next 87,000 kWh 0.050 for all over 90,000 kWh All over 400 kWh/kW billing demand: 0.048 for 1st 1,000,000 kWh 0.047 over 1,000,000 kWh
Demand charge ($/kW)	16.08	4.72/kW over 30 kW

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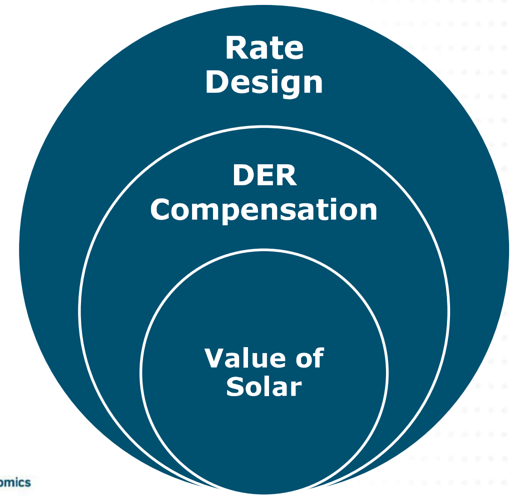
APPENDIX C: RATE DESIGN PRINCIPLES IN THE CONTEXT OF DER COMPENSATION

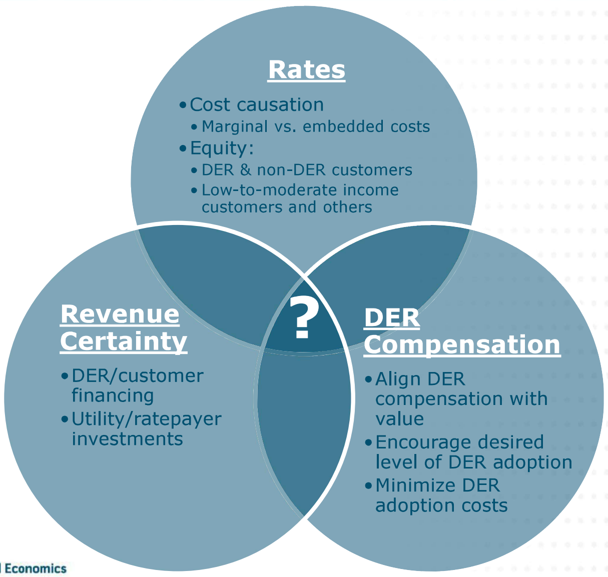
First Principle:

Rate design encompasses many issues; some of which are related, while many others are not

+ **DER compensation and the value of solar are embedded issues within the larger set of general rate design concerns**

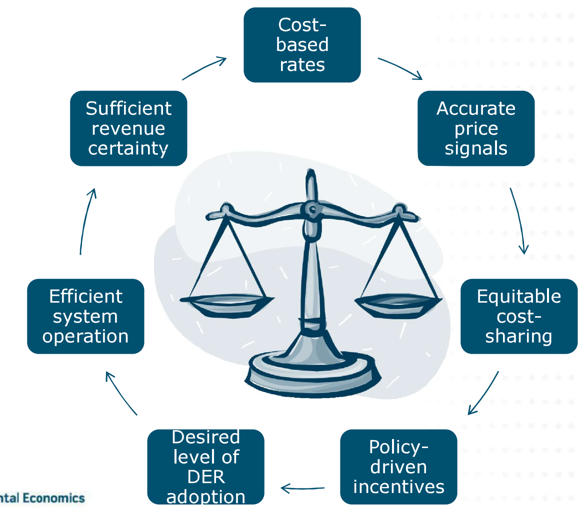


Second principle:
There is <u>no</u> perfect intersection between the "right" retail rate and the "best" type of DER compensation



Third Principle:
Compromise and balance is needed for equitable and sustainable DER compensation within rate design

+ ***<u>Goal:</u>*** **Retail rates and DER compensation mechanisms that accurately reflect <u>South Carolina</u> values**



Here's one set of illustrative retail rate/DER compensation principles

+ **Efficiency:**
  - Rates should promote efficient investment and consumption decisions by customers, which if tied to the utility avoided costs minimize the total costs of delivered energy to customers
+ **Equity:**
  - Costs should be allocated fairly and equitably among customer classes and customers within the class when rate components are based on embedded costs
+ **Rates should be simple, stable, understandable, acceptable to the public, and easily administered**
+ **Innovative rate designs should be tested prior to full scale implementation**
+ **Rates should support public policy, as applicable**